UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended September 30, 2018

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-10042

Atmos Energy Corporation

(Exact name of registrant as specified in its charter)

Texas and Virginia	**75-1743247**
(State or other jurisdiction of incorporation or organization)	*(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 **5430 LBJ Freeway, Dallas, Texas**	**75240**
(Address of principal executive offices)	*(Zip code)*

Registrant's telephone number, including area code:

(972) 934-9227

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, No Par Value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of the common voting stock held by non-affiliates of the registrant as of the last business day of the registrant's most recently completed second fiscal quarter, March 31, 2018, was $9,175,655,493.

As of November 8, 2018, the registrant had 111,352,649 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Definitive Proxy Statement to be filed for the Annual Meeting of Shareholders on February 6, 2019 are incorporated by reference into Part III of this report.

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GLOSSARY OF KEY TERMS

Adjusted diluted EPS from continuing operations	Non-GAAP measure defined as diluted earnings per share from continuing operations before the one-time, non-cash income tax benefit
Adjusted income from continuing operations	Non-GAAP measure defined as income from continuing operations before the one-time, non-cash income tax benefit
AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated Other Comprehensive Income
ARM	Annual Rate Mechanism
ATO	Trading symbol for Atmos Energy Corporation common stock on the NYSE
Bcf	Billion cubic feet
Contribution Margin	Non-GAAP measure defined as operating revenues less purchased gas cost
COSO	Committee of Sponsoring Organizations of the Treadway Commission
DARR	Dallas Annual Rate Review
ERISA	Employee Retirement Income Security Act of 1974
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
GRIP	Gas Reliability Infrastructure Program
GSRS	Gas System Reliability Surcharge
LTIP	1998 Long-Term Incentive Plan
Mcf	Thousand cubic feet
MDWQ	Maximum daily withdrawal quantity
Mid-Tex ATM Cities	Represents a coalition of 47 incorporated cities or approximately 8 percent of the Mid-Tex Division's customers.
Mid-Tex Cities	Represents all incorporated cities other than Dallas and Mid-Tex ATM Cities, or approximately 72 percent of the Mid-Tex Division's customers.
MMcf	Million cubic feet
Moody's	Moody's Investor Service, Inc.
NGA	Natural Gas Act of 1938
NYMEX	New York Mercantile Exchange, Inc.
NYSE	New York Stock Exchange
PHMSA	Pipeline and Hazardous Materials Safety Administration
PPA	Pension Protection Act of 2006
PRP	Pipeline Replacement Program
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
RSC	Rate Stabilization Clause
S&P	Standard & Poor's Corporation
SAVE	Steps to Advance Virginia Energy
SEC	United States Securities and Exchange Commission
SGR	Supplemental Growth Rider
SIR	System Integrity Rider
SRF	Stable Rate Filing
SSIR	System Safety and Integrity Rider
TCJA	Tax Cuts and Jobs Act of 2017
WNA	Weather Normalization Adjustment

PART I

The terms “we,” “our,” “us”, “Atmos Energy” and the “Company” refer to Atmos Energy Corporation and its subsidiaries, unless the context suggests otherwise.

ITEM 1. *Business.*

Overview and Strategy

Atmos Energy Corporation, headquartered in Dallas, Texas, and incorporated in Texas and Virginia, is one of the country’s largest natural-gas-only distributors based on number of customers. We deliver safe, clean, reliable, efficient, affordable and abundant natural gas through regulated sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers in eight states located primarily in the South. We also operate one of the largest intrastate pipelines in Texas based on miles of pipe.

Atmos Energy's vision is to be the safest provider of natural gas services. We intend to achieve this vision by:

- operating our business exceptionally well
- investing in our people and infrastructure
- enhancing our culture.

Since 2011, our operating strategy has focused on modernizing our distribution and transmission system to improve safety and reliability. Since that time, our capital expenditures have increased approximately 13% annually. Additionally, during this period, we have added new or modified existing regulatory mechanisms to reduce regulatory lag. Our ability to increase capital spending annually to modernize our system has increased our rate base, which has resulted in rising earnings per share and shareholder value.

Our core values include focusing on our employees and customers while conducting our business with honesty and integrity. We continue to strengthen our culture through ongoing communications with our employees and enhanced employee training.

Operating Segments

As of September 30, 2018, we manage and review our consolidated operations through the following three reportable segments:

- The *distribution segment* is primarily comprised of our regulated natural gas distribution and related sales operations in eight states.
- The *pipeline and storage segment* is comprised primarily of the pipeline and storage operations of our Atmos Pipeline-Texas division and our natural gas transmission operations in Louisiana.
- The *natural gas marketing segment* is comprised of our discontinued natural gas marketing business.

These operating segments are described in greater detail below.

Distribution Segment Overview

Our distribution segment is primarily comprised of our regulated natural gas distribution and related sales operations in eight states. The following table summarizes key information about our six regulated natural gas distribution divisions, presented in order of total rate base.

Division	Service Areas	Communities Served	Customer Meters
Mid-Tex	Texas, including the Dallas/Fort Worth Metroplex	550	1,697,171
Kentucky/Mid-States	Kentucky	230	182,510
	Tennessee		150,661
	Virginia		24,396
Louisiana	Louisiana	270	362,233
West Texas	Amarillo, Lubbock, Midland	80	313,828
Mississippi	Mississippi	110	269,333
Colorado-Kansas	Colorado	170	120,384
	Kansas		135,820

We operate in our service areas under terms of non-exclusive franchise agreements granted by the various cities and towns that we serve. At September 30, 2018, we held 1,013 franchises having terms generally ranging from five to 35 years. A significant number of our franchises expire each year, which require renewal prior to the end of their terms. Historically, we have successfully renewed these franchises and believe that we will continue to be able to renew our franchises as they expire.

Revenues in this operating segment are established by regulatory authorities in the states in which we operate. These rates are intended to be sufficient to cover the costs of conducting business, including a reasonable return on invested capital. In addition, we transport natural gas for others through our distribution systems.

Rates established by regulatory authorities often include cost adjustment mechanisms for costs that (i) are subject to significant price fluctuations compared to our other costs, (ii) represent a large component of our cost of service and (iii) are generally outside our control.

Purchased gas cost adjustment mechanisms represent a common form of cost adjustment mechanism. Purchased gas cost adjustment mechanisms provide natural gas distribution companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case because they provide a dollar-for-dollar offset to increases or decreases in the cost natural gas. Therefore, although substantially all of our distribution operating revenues fluctuate with the cost of gas that we purchase, distribution Contribution Margin (a Non-GAAP measure defined as operating revenues less purchased gas cost) is generally not affected by fluctuations in the cost of gas.

Additionally, some jurisdictions have performance-based ratemaking adjustments to provide incentives to distribution companies to minimize purchased gas costs through improved storage management and use of financial instruments to lock in gas costs. Under the performance-based ratemaking adjustments, purchased gas costs savings are shared between the utility and its customers.

Our supply of natural gas is provided by a variety of suppliers, including independent producers, marketers and pipeline companies, withdrawals of gas from proprietary and contracted storage assets and peaking and spot purchase agreements, as needed.

Supply arrangements consist of both base load and swing supply (peaking) quantities and are contracted from our suppliers on a firm basis with various terms at market prices. Base load quantities are those that flow at a constant level throughout the month and swing supply quantities provide the flexibility to change daily quantities to match increases or decreases in requirements related to weather conditions.

Except for local production purchases, we select our natural gas suppliers through a competitive bidding process by periodically requesting proposals from suppliers that have demonstrated that they can provide reliable service. We select these suppliers based on their ability to deliver gas supply to our designated firm pipeline receipt points at the lowest reasonable cost. Major suppliers during fiscal 2018 were Castleton Commodities Merchant Trading L.P., CenterPoint Energy Services, Inc., Concord Energy LLC, ConocoPhillips Company, Devon Gas Services, L.P., DTE Energy Trading Inc., Mieco Inc., Sequent Energy Management, L.P., Targa Gas Marketing LLC and Tenaska Gas Storage & Marketing Ventures, LLC.

The combination of base load, peaking and spot purchase agreements, coupled with the withdrawal of gas held in storage, allows us the flexibility to adjust to changes in weather, which minimizes our need to enter into long-term firm commitments. We estimate our peak-day availability of natural gas supply to be approximately 4.4 Bcf. The peak-day demand for our distribution operations in fiscal 2018 was on January 16, 2018, when sales to customers reached approximately 3.8 Bcf.

Currently, our distribution divisions utilize 38 pipeline transportation companies, both interstate and intrastate, to transport our natural gas. The pipeline transportation agreements are firm and many of them have "pipeline no-notice" storage service, which provides for daily balancing between system requirements and nominated flowing supplies. These agreements have been negotiated with the shortest term necessary while still maintaining our right of first refusal. The natural gas supply for our Mid-Tex Division is delivered primarily by our Atmos Pipeline — Texas Division (APT).

To maintain our deliveries to high priority customers, we have the ability, and have exercised our right, to curtail deliveries to certain customers under the terms of interruptible contracts or applicable state regulations or statutes. Our customers' demand on our system is not necessarily indicative of our ability to meet current or anticipated market demands or immediate delivery requirements because of factors such as the physical limitations of gathering, storage and transmission systems, the duration and severity of cold weather, the availability of gas reserves from our suppliers, the ability to purchase additional supplies on a short-term basis and actions by federal and state regulatory authorities. Curtailment rights provide us the flexibility to meet the human-needs requirements of our customers on a firm basis. Priority allocations imposed by federal and state regulatory agencies, as well as other factors beyond our control, may affect our ability to meet the demands of our customers. We do not anticipate any problems with obtaining additional gas supply as needed for our customers.

Pipeline and Storage Segment Overview

Our pipeline and storage segment consists of the pipeline and storage operations of APT and our natural gas transmission operations in Louisiana. APT is one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas-producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Barnett Shale, the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. Through its system, APT provides transportation and storage services to our Mid-Tex Division, other third party local distribution companies, industrial and electric generation customers, marketers and producers. As part of its pipeline operations, APT owns and operates five underground storage reservoirs in Texas.

Revenues earned from transportation and storage services for APT are subject to traditional ratemaking governed by the RRC. Rates are updated through periodic filings made under Texas' Gas Reliability Infrastructure Program (GRIP). GRIP allows us to include in our rate base annually approved capital costs incurred in the prior calendar year provided that we file a complete rate case at least once every five years; the most recent of which was completed in August 2017. APT's existing regulatory mechanisms allow certain transportation and storage services to be provided under market-based rates.

Our natural gas transmission operations in Louisiana are comprised of a proprietary 21-mile pipeline located in the New Orleans, Louisiana area that is primarily used to aggregate gas supply for our distribution division in Louisiana under a long-term contract and on a more limited basis, to third parties. The demand fee charged to our Louisiana distribution division for these services is subject to regulatory approval by the Louisiana Public Service Commission. We also manage two asset management plans in Louisiana that serve distribution affiliates of the Company, which have been approved by applicable state regulatory commissions. Generally, these asset management plans require us to share with our distribution customers a significant portion of the cost savings earned from these arrangements.

Natural Gas Marketing Segment Overview

Through December 31, 2016, we were engaged in a nonregulated natural gas marketing business, which was conducted by Atmos Energy Marketing (AEM). AEM's primary business was to aggregate and purchase gas supply, arrange transportation and storage logistics and ultimately deliver gas to customers at competitive prices. Additionally, AEM utilized proprietary and customer-owned transportation and storage assets to provide various services to its customers requested.

As more fully described in Note 15, effective January 1, 2017, we sold all of the equity interests of AEM to CenterPoint Energy Services, Inc. (CES), a subsidiary of CenterPoint Energy Inc. As a result of the sale, Atmos Energy has fully exited the nonregulated natural gas marketing business. Accordingly, these operations have been reported as discontinued operations.

Ratemaking Activity

Overview

The method of determining regulated rates varies among the states in which our regulated businesses operate. The regulatory authorities have the responsibility of ensuring that utilities in their jurisdictions operate in the best interests of customers while providing utility companies the opportunity to earn a reasonable return on their investment. Generally, each regulatory authority reviews rate requests and establishes a rate structure intended to generate revenue sufficient to cover the costs of conducting business, including a reasonable return on invested capital.

Our rate strategy focuses on reducing or eliminating regulatory lag, obtaining adequate returns and providing stable, predictable margins, which benefit both our customers and the Company. As a result of our ratemaking efforts in recent years, Atmos Energy has:

- Formula rate mechanisms in place in four states that provide for an annual rate review and adjustment to rates.

- Infrastructure programs in place in the majority of our states that provide for an annual adjustment to rates for qualifying capital expenditures. Through our annual formula rate mechanisms and infrastructure programs, we have the ability to recover over 85 percent of our capital expenditures within six months and 99 percent within twelve months.
- Authorization in tariffs, statute or commission rules that allows us to defer certain elements of our cost of service such as depreciation, ad valorem taxes and pension costs, until they are included in rates.
- WNA mechanisms in seven states that serve to minimize the effects of weather on approximately 97 percent of our distribution Contribution Margin.
- The ability to recover the gas cost portion of bad debts in five states.

The following table provides a jurisdictional rate summary for our regulated operations as of September 30, 2018. This information is for regulatory purposes only and may not be representative of our actual financial position.

Division	Jurisdiction	Effective Date of Last Rate/ GRIP Action	Rate Base (thousands)(1)	Authorized Rate of Return(1)	Authorized Debt/ Equity Ratio	Authorized Return on Equity(1)
Atmos Pipeline — Texas	Texas	05/22/2018	$2,122,194	8.87%	47/53	11.50%
Colorado-Kansas	Colorado	05/03/2018	134,726	7.55%	44/56	9.45%
	Colorado SSIR	01/01/2018	29,855	7.82%	48/52	9.60%
	Kansas	03/17/2016	200,564	(3)	(3)	(3)
	Kansas GSRS	02/27/2018	12,514	(3)	(3)	(3)
Kentucky/Mid-States	Kentucky	05/03/2018	427,646	7.41%	47/53	9.70%
	Tennessee(8)	06/01/2017	302,953	7.49%	47/53	9.80%
	Virginia	12/27/2016	47,581	(3)	(3)	(3)
Louisiana	Trans La	05/01/2018	169,120	7.26%	49/51	9.80%
	LGS	07/01/2018	419,080	7.55%	44/56	9.80%
Mid-Tex Cities	Texas(9)	06/01/2017	2,362,937(2)	8.36%	45/55	10.50%
Mid-Tex — Dallas	Texas	02/14/2018	(3)	(3)	(3)	(3)
Mississippi	Mississippi(7)	01/01/2018	377,954	7.47%	47/53	9.67%
	Mississippi - SIR(7)	01/01/2018	70,141	7.60%	47/53	9.92%
	Mississippi - SGR	01/01/2018	23,718	8.70%	47/53	12.00%
West Texas(4)	Texas(10)	03/15/2017	(3)	(3)	(3)	10.50%
	Texas-GRIP	06/05/2018	507,831	8.57%	48/52	10.50%

Division	Jurisdiction	Bad Debt Rider(5)	Formula Rate	Infrastructure Mechanism	Performance Based Rate Program(6)	WNA Period
Atmos Pipeline — Texas	Texas	No	Yes	Yes	N/A	N/A
Colorado-Kansas	Colorado	No	No	Yes	No	N/A
	Kansas	Yes	No	Yes	No	October-May
Kentucky/Mid-States	Kentucky	Yes	No	No	Yes	November-April
	Tennessee	Yes	Yes	No	Yes	October-April
	Virginia	Yes	No	Yes	No	January-December
Louisiana	Trans La	No	Yes	Yes	No	December-March
	LGS	No	Yes	Yes	No	December-March
Mid-Tex Cities	Texas	Yes	Yes	Yes	No	November-April
Mid-Tex — Dallas	Texas	Yes	Yes	Yes	No	November-April
Mississippi	Mississippi	No	Yes	Yes	Yes	November-April
West Texas(4)	Texas	Yes	Yes	Yes	No	October-May

(1) The rate base, authorized rate of return and authorized return on equity presented in this table are those from the most recent regulatory filing for each jurisdiction. These rate bases, rates of return and returns on equity are not necessarily indicative of current or future rate bases, rates of return or returns on equity.
(2) The Mid-Tex rate base represents a "system-wide", or 100 percent, of the Mid-Tex Division's rate base.
(3) A rate base, rate of return, return on equity or debt/equity ratio was not included in the respective state commission's final decision.
(4) The West Texas Cities includes all West Texas Division cities except Amarillo, Channing, Dalhart and Lubbock.
(5) The bad debt rider allows us to recover from ratepayers the gas cost portion of uncollectible accounts.
(6) The performance-based rate program provides incentives to distribution companies to minimize purchased gas costs by allowing the companies and their customers to share the purchased gas costs savings.
(7) The Mississippi Public Service Commission approved a settlement at its meeting on October 23, 2018, which included a rate base of $541.7 million, an authorized return of 7.81%, a debt/equity ratio of 45/55 and an authorized ROE of 10.24%. New rates were implemented November 1, 2018.
(8) The Tennessee Public Utility Commission approved the Formula Rate Mechanism filing at its meeting on October 15, 2018, which included a rate base of $351.8 million, an authorized return of 7.26%, a debt/equity ratio of 49/51 and an authorized ROE of 9.8%.
(9) The Mid-Tex Cities approved the Formula Rate Mechanism filing with rates effective October 1, 2018, which included a rate base of $2,587.3 million, an authorized return of 7.87%, a debt/equity ratio of 42/58 and an authorized ROE of 9.80%.
(10) The West Texas Cities approved the Formula Rate Mechanism filing with rates effective October 1, 2018, which included a rate base of $505.7 million, an authorized return of 7.87%, a debt/equity ratio of 42/58 and an authorized ROE of 9.80%.

Although substantial progress has been made in recent years to improve rate design and recovery of investment across our service areas, we are continuing to seek improvements in rate design to address cost variations and pursue tariffs that reduce regulatory lag associated with investments. Further, potential changes in federal energy policy, federal safety regulations and changing economic conditions will necessitate continued vigilance by the Company and our regulators in meeting the challenges presented by these external factors.

Recent Ratemaking Activity

Net operating income increases resulting from ratemaking activity totaling $80.1 million, $104.2 million and $122.5 million, became effective in fiscal 2018, 2017 and 2016, as summarized below. The ratemaking outcomes for fiscal 2018 include the effect of tax reform legislation enacted effective January 1, 2018 and do not reflect the true economic benefit of the outcomes because they do not include the corresponding income tax benefit we will receive due to the decrease in our statutory tax rate.

Rate Action	Annual Increase (Decrease) to Operating Income For the Fiscal Year Ended September 30 2018	2017	2016
		(In thousands)	
Annual formula rate mechanisms	$ 92,472	$ 90,427	$ 114,974
Rate case filings	(12,853)	12,961	7,716
Other ratemaking activity	457	784	(183)
	$ 80,076	$ 104,172	$ 122,507

Additionally, the following ratemaking efforts seeking $52.8 million in annual operating income were initiated during fiscal 2018 but had not been completed as of September 30, 2018:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Mid-Tex	Formula Rate Mechanism	Mid-Tex Cities (1) (2)	$ 28,036
Mid-Tex	Rate Case	ATM Cities (1)	4,252
Mid-Tex	Rate Case	Environs (1) (7)	(1,875)
Mississippi	Infrastructure Mechanism	Mississippi (1) (3)	7,976
Mississippi	Formula Rate Mechanism	Mississippi (1) (3)	4,119
Kentucky/Mid-States	Formula Rate Mechanism	Tennessee (1) (4)	(5,032)
Kentucky/Mid-States	Formula Rate Mechanism True-Up	Tennessee (1) (5)	(3,220)
Kentucky/Mid-States	Rate Case	Kentucky (1)	14,424
Kentucky/Mid-States	Rate Case	Virginia (1)	605
West Texas	Formula Rate Mechanism	WT Cities (1) (6)	4,030
West Texas	Rate Case	Environs (1) (7)	(485)
			$ 52,830

(1) The filing amount reflects a 21% federal income tax rate resulting from the Tax Cuts and Jobs Act of 2017 (TCJA).
(2) The Mid-Tex Cities approved a rate increase of $17.6 million effective October 1, 2018.
(3) The Mississippi Public Service Commission approved a settlement at its meeting on October 23, 2018, for a combined $7.0 million increase. New rates were implemented November 1, 2018.
(4) The Tennessee Public Utility Commission approved the Formula Rate Mechanism filing, which included $0.4 million related to the May 2017 true-up, at its October 15, 2018 meeting.
(5) The Tennessee Formula Rate Mechanism Test Period Ended May 2018 reflects the discontinuance of the prior year true-up.
(6) The West Texas Cities approved a rate increase of $2.8 million effective October 1, 2018.
(7) Settlement pending Texas Railroad Commission approval.

Our recent ratemaking activity is discussed in greater detail below.

Annual Formula Rate Mechanisms

As an instrument to reduce regulatory lag, formula rate mechanisms allow us to refresh our rates on an annual basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. The following table summarizes our annual formula rate mechanisms by state.

	Annual Formula Rate Mechanisms	
State	**Infrastructure Programs**	**Formula Rate Mechanisms**
Colorado	System Safety and Integrity Rider (SSIR)	—
Kansas	Gas System Reliability Surcharge (GSRS)	—
Kentucky	Pipeline Replacement Program (PRP)	—
Louisiana	(1)	Rate Stabilization Clause (RSC)
Mississippi	System Integrity Rider (SIR)	Stable Rate Filing (SRF), Supplemental Growth Filing (SGR)
Tennessee	—	Annual Rate Mechanism (ARM)
Texas	Gas Reliability Infrastructure Program (GRIP), (1)	Dallas Annual Rate Review (DARR), Rate Review Mechanism (RRM)
Virginia	Steps to Advance Virginia Energy (SAVE)	—

(1) Infrastructure mechanisms in Texas and Louisiana allow for the deferral of all expenses associated with capital expenditures incurred pursuant to these rules, which primarily consists of interest, depreciation and other taxes (Texas only), until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recoverable through base rates.

The following table summarizes our annual formula rate mechanisms with effective dates during the fiscal years ended September 30, 2018, 2017 and 2016:

Division	Jurisdiction	Test Year Ended	Increase (Decrease) in Annual Operating Income (In thousands)	Effective Date
2018 Filings:				
Louisiana	LGS[1]	12/2017	$ (1,521)	07/01/2018
West Texas	Amarillo, Lubbock, Dalhart and Channing[1]	12/2017	4,418	06/08/2018
Mid-Tex	Environs[1]	12/2017	1,604	06/05/2018
West Texas	Environs[1]	12/2017	826	06/05/2018
Atmos Pipeline - Texas	Texas[1]	12/2017	42,173	05/22/2018
Louisiana	Trans La[1]	09/2017	(1,913)	05/01/2018
Colorado-Kansas	Kansas GSRS	09/2018	820	02/27/2018
Mississippi	Mississippi - SIR	10/2018	7,658	01/01/2018
Mississippi	Mississippi - SGR [2]	10/2018	1,245	01/01/2018
Mississippi	Mississippi - SRF [2]	10/2018	—	01/01/2018
Colorado-Kansas	Colorado SSIR	12/2018	2,228	12/20/2017
Atmos Pipeline - Texas	Texas	12/2016	28,988	12/05/2017
Kentucky/Mid-States	Kentucky - PRP	09/2018	5,638	10/27/2017
Kentucky/Mid-States	Virginia - SAVE [3]	09/2017	308	10/01/2017
Total 2018 Filings			$ 92,472	
2017 Filings:				
Louisiana	LGS	12/2016	$ 6,237	07/01/2017
Mid-Tex	Mid-Tex DARR	09/2016	9,672	06/01/2017
Mid-Tex	Mid-Tex Cities RRM	12/2016	36,239	06/01/2017
Kentucky/Mid-States	Tennessee ARM	05/2018	6,740	06/01/2017
Mid-Tex	Mid-Tex Environs	12/2016	1,568	05/23/2017
West Texas	West Texas Environs	12/2016	872	05/23/2017
West Texas	West Texas ALDC	12/2016	4,682	04/25/2017
Louisiana	Trans La	09/2016	4,392	04/01/2017
West Texas	West Texas Cities RRM	09/2016	4,255	03/15/2017
Colorado-Kansas	Kansas	09/2016	801	02/09/2017
Mississippi	Mississippi - SRF	10/2017	4,390	02/01/2017
Mississippi	Mississippi - SIR	10/2017	3,334	01/01/2017
Mississippi	Mississippi - SGR	10/2017	1,292	01/01/2017
Colorado-Kansas	Colorado - SSIR	12/2017	1,350	01/01/2017
Kentucky/Mid-States	Kentucky - PRP	09/2017	4,981	10/14/2016
Kentucky/Mid-States	Virginia - SAVE	09/2017	(378)	10/01/2016
Total 2017 Filings			$ 90,427	
2016 Filings:				
Louisiana	LGS	12/2015	$ 8,686	07/01/2016
Kentucky/Mid-States	Tennessee	05/2017	4,888	06/01/2016
Mid-Tex	Mid-Tex Cities RRM	12/2015	25,816	06/01/2016

Mid-Tex	Mid-Tex DARR	09/2015	5,429	06/01/2016
Mid-Tex	Mid-Tex Environs	12/2015	1,325	05/03/2016
Atmos Pipeline - Texas	Texas	12/2015	40,658	05/03/2016
West Texas	West Texas Environs	12/2015	646	05/03/2016
West Texas	West Texas ALDC	12/2015	3,484	04/26/2016
Louisiana	Trans La	09/2015	6,216	04/01/2016
Colorado-Kansas	Colorado	12/2016	764	01/01/2016
Mississippi	Mississippi - SRF	10/2016	9,192	01/01/2016
Mississippi	Mississippi - SGR	10/2016	250	12/01/2015
Kentucky/Mid-States	Kentucky - PRP	09/2016	3,786	10/01/2015
Kentucky/Mid-States	Virginia - SAVE	09/2016	118	10/01/2015
West Texas	West Texas Cities	09/2015	3,716	10/01/2015
Total 2016 Filings			$ 114,974	

(1) The operating income reflects a 21% federal income tax rate resulting from the TCJA.
(2) In our next SRF filing, the SGR rate base will be combined with the SRF rate base, per Commission order.
(3) The Company completed our Steps to Advance Virginia Energy (SAVE) program. On October 1, 2017 a refund factor was removed from the rate resulting in an operating income increase of $0.3 million.

Rate Case Filings

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a “show cause” action. Adequate rates are intended to provide for recovery of the Company’s costs as well as a fair rate of return to our shareholders and ensure that we continue to safely deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes our recent rate cases:

Division	State	Increase (Decrease) in Annual Operating Income	Effective Date
		(In thousands)	
2018 Rate Case Filings:			
Colorado-Kansas	Colorado [(1)]	$ (241)	05/03/2018
Kentucky/Mid-States	Kentucky [(1)]	(7,504)	05/03/2018
Mid-Tex	City of Dallas [(1)]	(5,108)	02/14/2018
Total 2018 Rate Case Filings		$ (12,853)	
2017 Rate Case Filings:			
Atmos Pipeline - Texas	Texas	$ 12,955	08/01/2017
Kentucky/Mid-States	Virginia	6	12/27/2016
Total 2017 Rate Case Filings		$ 12,961	
2016 Rate Case Filings:			
Kentucky/Mid-States	Kentucky	$ 2,723	08/15/2016
Kentucky/Mid-States	Virginia	537	04/01/2016
Colorado-Kansas	Kansas	2,372	03/17/2016
Colorado-Kansas	Colorado	2,084	01/01/2016
Total 2016 Rate Case Filings		$ 7,716	

(1) The operating income reflects a 21% federal income tax rate resulting from the TCJA.

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the fiscal years ended September 30, 2018, 2017 and 2016:

Division	Jurisdiction	Rate Activity	Increase (Decrease) in Annual Operating Income	Effective Date
			(In thousands)	
2018 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem[1]	$ 457	02/01/2018
Total 2018 Other Rate Activity			$ 457	
2017 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad-Valorem[1]	$ 784	02/01/2017
Total 2017 Other Rate Activity			$ 784	
2016 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad-Valorem[1]	$ (183)	02/01/2016
Total 2016 Other Rate Activity			$ (183)	

(1) The Ad Valorem filing relates to property taxes that are either over or uncollected compared to the amount included in our Kansas service area's base rates.

Other Regulation

We are regulated by various state or local public utility authorities. We are also subject to regulation by the United States Department of Transportation with respect to safety requirements in the operation and maintenance of our transmission and distribution facilities. In addition, our operations are also subject to various state and federal laws regulating environmental matters. From time to time, we receive inquiries regarding various environmental matters. We believe that our properties and operations substantially comply with, and are operated in substantial conformity with, applicable safety and environmental statutes and regulations. There are no administrative or judicial proceedings arising under environmental quality statutes pending or known to be contemplated by governmental agencies which would have a material adverse effect on us or our operations. Our environmental claims have arisen primarily from former manufactured gas plant sites. The Pipeline and Hazardous Materials Safety Administration (PHMSA), within the U.S. Department of Transportation, develops and enforces regulations for the safe, reliable and environmentally sound operation of the pipeline transportation system. The PHMSA pipeline safety statutes provide for states to assume safety authority over intrastate and natural gas pipelines. State pipeline safety programs are responsible for adopting and enforcing the federal and state pipeline safety regulations for intrastate natural gas transmission and distribution pipelines.

The Federal Energy Regulatory Commission (FERC) allows, pursuant to Section 311 of the Natural Gas Policy Act (NGA), gas transportation services through our Atmos Pipeline—Texas assets "on behalf of" interstate pipelines or local distribution companies served by interstate pipelines, without subjecting these assets to the jurisdiction of the FERC under the NGA. Additionally, the FERC has regulatory authority over the use and release of interstate pipeline and storage capacity. The FERC also has authority to detect and prevent market manipulation and to enforce compliance with FERC's other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. We have taken what we believe are the necessary and appropriate steps to comply with these regulations.

The SEC and the Commodities Futures Trading Commission, pursuant to the Dodd–Frank Act, established numerous regulations relating to U.S. financial markets. We enacted procedures and modified existing business practices and contractual arrangements to comply with such regulations. There are, however, some rulemaking proceedings that have not yet been finalized, including those relating to capital and margin rules for (non–cleared) swaps. We do not expect these rules to directly impact our business practices or collateral requirements. However, depending on the substance of these final rules, in addition to certain international regulatory requirements still under development that are similar to Dodd–Frank, our swap counterparties could be subject to additional and potentially significant capitalization requirements. These regulations could motivate counterparties to increase our collateral requirements or cash postings.

Competition

Although our regulated distribution operations are not currently in significant direct competition with any other distributors of natural gas to residential and commercial customers within our service areas, we do compete with other natural gas suppliers and suppliers of alternative fuels for sales to industrial customers. We compete in all aspects of our business with alternative energy sources, including, in particular, electricity. Electric utilities offer electricity as a rival energy source and compete for the space heating, water heating and cooking markets. Promotional incentives, improved equipment efficiencies and promotional rates all contribute to the acceptability of electrical equipment. The principal means to compete against alternative fuels is lower prices, and natural gas historically has maintained its price advantage in the residential, commercial and industrial markets.

Our pipeline and storage operations have historically faced competition from other existing intrastate pipelines seeking to provide or arrange transportation, storage and other services for customers. In the last few years, several new pipelines have been completed, which has increased the level of competition in this segment of our business.

Employees

At September 30, 2018, we had 4,628 employees, consisting of 4,564 employees in our distribution operations and 64 employees in our pipeline and storage operations.

Available Information

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports, and amendments to those reports, and other forms that we file with or furnish to the Securities and Exchange Commission (SEC) at their website, *www.sec.gov*, are also available free of charge at our website, *www.atmosenergy.com*, under "Publications and Filings" under the "Investors" tab, as soon as reasonably practicable, after we electronically file these reports with, or furnish these reports to, the SEC. We will also provide copies of these reports free of charge upon request to Shareholder Relations at the address and telephone number appearing below:

Shareholder Relations
Atmos Energy Corporation
P.O. Box 650205
Dallas, Texas 75265-0205
972-855-3729

Corporate Governance

In accordance with and pursuant to relevant related rules and regulations of the SEC as well as corporate governance-related listing standards of the New York Stock Exchange (NYSE), the Board of Directors of the Company has established and periodically updated our Corporate Governance Guidelines and Code of Conduct, which is applicable to all directors, officers and employees of the Company. In addition, in accordance with and pursuant to such NYSE listing standards, our Chief Executive Officer during fiscal 2018, Michael E. Haefner, certified to the New York Stock Exchange that he was not aware of any violations by the Company of NYSE corporate governance listing standards. The Board of Directors also annually reviews and updates, if necessary, the charters for each of its Audit, Human Resources and Nominating and Corporate Governance Committees. All of the foregoing documents are posted on the Corporate Responsibility page of our website. We will also provide copies of all corporate governance documents free of charge upon request to Shareholder Relations at the address listed above.

ITEM 1A. *Risk Factors.*

Our financial and operating results are subject to a number of risk factors, many of which are not within our control. Although we have tried to discuss key risk factors below, please be aware that other or new risks may prove to be important in the future. Investors should carefully consider the following discussion of risk factors as well as other information appearing in this report. These factors include the following:

We are subject to state and local regulations that affect our operations and financial results.

We are subject to regulatory oversight from various state and local regulatory authorities in the eight states that we serve. Therefore, our returns are continuously monitored and are subject to challenge for their reasonableness by the appropriate regulatory authorities or other third-party intervenors. In the normal course of business, as a regulated entity, we often need to place assets in service and establish historical test periods before rate cases that seek to adjust our allowed returns to recover that investment can be filed. Further, the regulatory review process can be lengthy in the context of traditional ratemaking. Because of this process, we suffer the negative financial effects of having placed assets in service without the benefit of rate relief, which is commonly referred to as "regulatory lag."

However, in the last several years, a number of regulatory authorities in the states we serve have approved rate mechanisms that provide for annual adjustments to rates that allow us to recover the cost of investments made to replace existing infrastructure or reflect changes in our cost of service. These mechanisms work to effectively reduce the regulatory lag inherent in the ratemaking process. However, regulatory lag could significantly increase if the regulatory authorities modify or terminate these rate mechanisms. The regulatory process also involves the risk that regulatory authorities may (i) review our purchases of natural gas and adjust the amount of our gas costs that we pass through to our customers or (ii) limit the costs we may have incurred from our cost of service that can be recovered from customers.

We are also subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to protection of the environment and health and safety matters, including those that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, the clean-up of contaminated sites, groundwater quality and availability, plant and wildlife protection, as well as work practices related to employee health and safety. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties or interruptions in our operations that could be significant to our financial results. In addition, existing environmental regulations may be revised or our operations may become subject to new regulations.

Some of our operations are subject to increased federal regulatory oversight that could affect our operations and financial results.

FERC has regulatory authority over some of our operations, including the use and release of interstate pipeline and storage capacity. FERC has adopted rules designed to prevent market power abuse and market manipulation and to promote compliance with FERC's other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. These rules carry increased penalties for violations. Although we have taken steps to structure current and future transactions to comply with applicable current FERC regulations, changes in FERC regulations or their interpretation by FERC or additional regulations issued by FERC in the future could also adversely affect our business, financial condition or financial results.

We may experience increased federal, state and local regulation of the safety of our operations.

The safety and protection of the public, our customers and our employees is our top priority. We constantly monitor and maintain our pipeline and distribution systems to ensure that natural gas is delivered safely, reliably and efficiently through our network of more than 75,000 miles of distribution and transmission lines. However, in recent years, natural gas distribution and pipeline companies have faced increasing federal, state and local oversight of the safety of their operations. Although we believe these costs should be ultimately recoverable through our rates, the costs of complying with new laws and regulations may have at least a short-term adverse impact on our operating costs and financial results.

Distributing, transporting and storing natural gas involve risks that may result in accidents and additional operating costs.

Our operations involve a number of hazards and operating risks inherent in storing and transporting natural gas that could affect the public safety and reliability of our distribution system. While Atmos Energy, with the support from each of its regulatory commissions, is accelerating the replacement of aging pipeline infrastructure, operating issues such as as leaks, accidents, equipment problems and incidents, including explosions and fire, could result in legal liability, repair and remediation costs, increased operating costs, significant increased capital expenditures, regulatory fines and penalties and other costs and a loss of customer confidence. We maintain liability and property insurance coverage in place for many of these hazards and risks. However, because some of our transmission pipeline and storage facilities are near or are in populated areas, any loss of human life or adverse financial results resulting from such events could be large. If these events were not fully covered by our general liability and property insurance, which policies are subject to certain limits and deductibles, our operations or financial results could be adversely affected.

Our growth in the future may be limited by the nature of our business, which requires extensive capital spending.

Our operations are capital-intensive. We must make significant capital expenditures on a long-term basis to modernize our distribution and transmission system to improve the safety and reliability and to comply with the safety rules and regulations issued by the regulatory authorities responsible for the service areas we operate. In addition, we must continually build new capacity to serve the growing needs of the communities we serve. The magnitude of these expenditures may be affected by a number of factors, including new regulations, the general state of the economy and weather.

The liquidity required to fund our working capital, capital expenditures and other cash needs is provided from a combination of internally generated cash flows and external debt and equity financing. The cost and availability of borrowing funds from third party lenders or issuing equity is dependent on the liquidity of the credit markets, interest rates and other market conditions. This in turn may limit the amount of funds we can invest in our infrastructure.

The Company is dependent on continued access to the credit and capital markets to execute our business strategy.

Our long-term debt is currently rated as "investment grade" by Standard & Poor's Corporation and Moody's Investors Service, Inc. Similar to most companies, we rely upon access to both short-term and long-term credit and capital markets to satisfy our liquidity requirements. If adverse credit conditions were to cause a significant limitation on our access to the private credit and public capital markets, we could see a reduction in our liquidity. A significant reduction in our liquidity could in turn trigger a negative change in our ratings outlook or even a reduction in our credit ratings by one or more of the credit rating agencies. Such a downgrade could further limit our access to private credit and/or public capital markets and increase our costs of borrowing.

While we believe we can meet our capital requirements from our operations and the sources of financing available to us, we can provide no assurance that we will continue to be able to do so in the future, especially if the market price of natural gas increases significantly in the near term. The future effects on our business, liquidity and financial results of a deterioration of current conditions in the credit and capital markets could be material and adverse to us, both in the ways described above or in other ways that we do not currently anticipate.

We are exposed to market risks that are beyond our control, which could adversely affect our financial results.

We are subject to market risks beyond our control, including (i) commodity price volatility caused by market supply and demand dynamics, counterparty performance or counterparty creditworthiness, and (ii) interest rate risk. We are generally insulated from commodity price risk through our purchased gas cost mechanisms. With respect to interest rate risk, we have been operating in a relatively low interest-rate environment in recent years compared to historical norms for both short and long-term interest rates. However, increases in interest rates could adversely affect our future financial results to the extent that we do not recover our actual interest expense in our rates.

The concentration of our operations in the State of Texas exposes our operations and financial results to economic conditions, weather patterns and regulatory decisions in Texas.

Approximately 70 percent of our consolidated operations are located in the State of Texas. This concentration of our business in Texas means that our operations and financial results may be significantly affected by changes in the Texas economy in general, weather patterns and regulatory decisions by state and local regulatory authorities in Texas.

A deterioration in economic conditions could adversely affect our customers and negatively impact our financial results.

Any adverse changes in economic conditions in the United States, especially in the states in which we operate, could adversely affect the financial resources of many domestic households. As a result, our customers could seek to use less gas and it may be more difficult for them to pay their gas bills. This would likely lead to slower collections and higher than normal levels of accounts receivable. This, in turn, could increase our financing requirements. Additionally, should economic conditions deteriorate, our industrial customers could seek alternative energy sources, which could result in lower sales volumes.

Increased gas costs could adversely impact our customer base and customer collections and increase our level of indebtedness.

Rapid increases in the costs of purchased gas would cause us to experience a significant increase in short-term debt. We must pay suppliers for gas when it is purchased, which can be significantly in advance of when these costs may be recovered through the collection of monthly customer bills for gas delivered. Increases in purchased gas costs also slow our natural gas distribution collection efforts as customers are more likely to delay the payment of their gas bills, leading to higher than normal accounts receivable. This could result in higher short-term debt levels, greater collection efforts and increased bad debt expense.

If contracted gas supplies, interstate pipeline and/or storage services are not available or delivered in a timely manner, our ability to meet our customers' natural gas requirements may be impaired and our financial condition may be adversely affected.

In order to meet our customers' annual and seasonal natural gas demands, we must obtain a sufficient supply of natural gas, interstate pipeline capacity and storage capacity. If we are unable to obtain these, either from our suppliers' inability to deliver the contracted commodity or the inability to secure replacement quantities, our financial condition and results of operations may be adversely affected. If a substantial disruption to or reduction in interstate natural gas pipelines' transmission and storage capacity occurred due to operational failures or disruptions, legislative or regulatory actions, hurricanes, tornadoes, floods, terrorist or cyber-attacks or acts of war, our operations or financial results could be adversely affected.

Our operations are subject to increased competition.

In residential and commercial customer markets, our distribution operations compete with other energy products, such as electricity and propane. Our primary product competition is with electricity for heating, water heating and cooking. Increases in the price of natural gas could negatively impact our competitive position by decreasing the price benefits of natural gas to the consumer. This could adversely impact our business if our customer growth slows or if our customers further conserve their use of gas, resulting in reduced gas purchases and customer billings.

In the case of industrial customers, such as manufacturing plants, adverse economic conditions, including higher gas costs, could cause these customers to use alternative sources of energy, such as electricity, or bypass our systems in favor of special competitive contracts with lower per-unit costs. Our pipeline and storage operations historically have faced limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, in the last few years, several new pipelines have been completed, which has increased the level of competition in this segment of our business.

Adverse weather conditions could affect our operations or financial results.

We have weather-normalized rates for approximately 97 percent of our residential and commercial meters in our distribution operations, which substantially mitigates the adverse effects of warmer-than-normal weather for meters in those service areas. However, there is no assurance that we will continue to receive such regulatory protection from adverse weather in our rates in the future. The loss of such weather-normalized rates could have an adverse effect on our operations and financial results. In addition, our operating results may continue to vary somewhat with the actual temperatures during the winter heating season. Additionally, sustained cold weather could challenge our ability to adequately meet customer demand in our operations.

The costs of providing health care benefits, pension and postretirement health care benefits and related funding requirements may increase substantially.

We provide health care benefits, a cash-balance pension plan and postretirement health care benefits to eligible full-time employees. The costs of providing health care benefits to our employees could significantly increase over time due to rapidly increasing health care inflation, and any future legislative changes related to the provision of health care benefits. The impact of additional costs which are likely to be passed on to the Company is difficult to measure at this time.

The costs of providing a cash-balance pension plan to eligible full-time employees prior to 2011 and postretirement health care benefits to eligible full-time employees and related funding requirements could be influenced by changes in the market value of the assets funding our pension and postretirement health care plans. Any significant declines in the value of these investments due to sustained declines in equity markets or a reduction in bond yields could increase the costs of our pension and postretirement health care plans and related funding requirements in the future. Further, our costs of providing such benefits and related funding requirements are also subject to a number of factors, including (i) changing demographics, including longer life expectancy of beneficiaries and an expected increase in the number of eligible former employees over the next five to ten years; (ii) various actuarial calculations and assumptions which may differ materially from actual results due primarily to changing market and economic conditions, including changes in interest rates, and higher or lower withdrawal rates; and (iii) future government regulation.

The costs to the Company of providing these benefits and related funding requirements could also increase materially in the future, should there be a material reduction in the amount of the recovery of these costs through our rates or should significant delays develop in the timing of the recovery of such costs, which could adversely affect our financial results.

The inability to continue to hire, train and retain operational, technical and managerial personnel could adversely affect our results of operations.

Although the average age of the employee base of Atmos Energy is not significantly changing year over year, there are still a number of employees who will become eligible to retire within the next five to 10 years. If we were unable to hire appropriate personnel or contractors to fill future needs, the Company could encounter operating challenges and increased costs, primarily due to a loss of knowledge, errors due to inexperience or the lengthy time period typically required to adequately train replacement personnel. In addition, higher costs could result from loss of productivity or increased safety compliance issues. The inability to hire, train and retain new operational, technical and managerial personnel adequately and to transfer institutional knowledge and expertise could adversely affect our ability to manage and operate our business. If we were unable to hire, train and retain appropriately qualified personnel, our results of operations could be adversely affected.

The operations and financial results of the Company could be adversely impacted as a result of climate change or related additional legislation or regulation in the future.

To the extent climate change occurs, our businesses could be adversely impacted, although we believe it is likely that any such resulting impacts would occur very gradually over a long period of time and thus would be difficult to quantify with any degree of specificity. To the extent climate change would result in warmer temperatures in our service territories, financial results could be adversely affected through lower gas volumes and revenues. Such climate change could also cause shifts in population, including customers moving away from our service territories near the Gulf Coast in Louisiana and Mississippi.

Another possible climate change would be more frequent and more severe weather events, such as hurricanes and tornadoes, which could increase our costs to repair damaged facilities and restore service to our customers. If we were unable to deliver natural gas to our customers, our financial results would be impacted by lost revenues, and we generally would have to seek approval from regulators to recover restoration costs. To the extent we would be unable to recover those costs, or if higher rates resulting from our recovery of such costs would result in reduced demand for our services, our future business, financial condition or financial results could be adversely impacted.

In addition, there have been a number of federal and state legislative and regulatory initiatives proposed in recent years in an attempt to control or limit the effects of global warming and overall climate change, including greenhouse gas emissions, such as carbon dioxide. The adoption of this type of legislation by Congress or similar legislation by states or the adoption of related regulations by federal or state governments mandating a substantial reduction in greenhouse gas emissions in the future could have far-reaching and significant impacts on the energy industry. Such new legislation or regulations could result in increased compliance costs for us or additional operating restrictions on our business, affect the demand for natural gas or impact the prices we charge to our customers. At this time, we cannot predict the potential impact of such laws or regulations that may be adopted on our future business, financial condition or financial results.

Cyber-attacks or acts of cyber-terrorism could disrupt our business operations and information technology systems or result in the loss or exposure of confidential or sensitive customer, employee or Company information.

Our business operations and information technology systems may be vulnerable to an attack by individuals or organizations intending to disrupt our business operations and information technology systems, even though the Company has implemented policies, procedures and controls to prevent and detect these activities. We use our information technology systems to manage our distribution and intrastate pipeline and storage operations and other business processes. Disruption of those systems could adversely impact our ability to safely deliver natural gas to our customers, operate our pipeline and storage systems or serve our customers timely. Accordingly, if such an attack or act of terrorism were to occur, our operations and financial results could be adversely affected.

In addition, we use our information technology systems to protect confidential or sensitive customer, employee and Company information developed and maintained in the normal course of our business. Any attack on such systems that would result in the unauthorized release of customer, employee or other confidential or sensitive data could have a material adverse effect on our business reputation, increase our costs and expose us to additional material legal claims and liability. Even though we have insurance coverage in place for many of these cyber-related risks, if such an attack or act of terrorism were to occur, our operations and financial results could be adversely affected to the extent not fully covered by such insurance coverage.

Natural disasters, terrorist activities or other significant events could adversely affect our operations or financial results.

Natural disasters are always a threat to our assets and operations. In addition, the threat of terrorist activities could lead to increased economic instability and volatility in the price of natural gas that could affect our operations. Also, companies in our industry may face a heightened risk of exposure to actual acts of terrorism, which could subject our operations to increased risks. As a result, the availability of insurance covering such risks may become more limited, which could increase the risk that an event could adversely affect our operations or financial results.

ITEM 1B. *Unresolved Staff Comments.*

Not applicable.

ITEM 2. *Properties.*

Distribution, transmission and related assets

At September 30, 2018, in our distribution segment, we owned an aggregate of 70,071 miles of underground distribution and transmission mains throughout our distribution systems. These mains are located on easements or rights-of-way. We maintain our mains through a program of continuous inspection and repair and believe that our system of mains is in good condition. Through our pipeline and storage segment we owned 5,678 miles of gas transmission lines as well.

Storage Assets

We own underground gas storage facilities in several states to supplement the supply of natural gas in periods of peak demand. The following table summarizes certain information regarding our underground gas storage facilities at September 30, 2018:

State	Usable Capacity (Mcf)	Cushion Gas (Mcf)(1)	Total Capacity (Mcf)	Maximum Daily Delivery Capability (Mcf)
Distribution Segment				
Kentucky	7,956,991	9,562,283	17,519,274	158,100
Kansas	3,239,000	2,300,000	5,539,000	45,000
Mississippi	1,907,571	2,442,917	4,350,488	31,000
Total	13,103,562	14,305,200	27,408,762	234,100
Pipeline and Storage Segment				
Texas	46,083,549	15,878,025	61,961,574	1,710,000
Louisiana	411,040	256,900	667,940	56,000
Total	46,494,589	16,134,925	62,629,514	1,766,000
Total	59,598,151	30,440,125	90,038,276	2,000,100

(1) Cushion gas represents the volume of gas that must be retained in a facility to maintain reservoir pressure.

Additionally, we contract for storage service in underground storage facilities on many of the interstate and intrastate pipelines serving us to supplement our proprietary storage capacity. The following table summarizes our contracted storage capacity at September 30, 2018:

Segment	Division/Company	Maximum Storage Quantity (MMBtu)	Maximum Daily Withdrawal Quantity (MDWQ)(1)
Distribution Segment			
	Colorado-Kansas Division	6,129,562	136,996
	Kentucky/Mid-States Division	8,175,103	226,739
	Louisiana Division	2,536,779	174,805
	Mid-Tex Division	5,500,000	225,000
	Mississippi Division	5,083,801	163,627
	West Texas Division	5,000,000	161,000
Total		32,425,245	1,088,167
Pipeline and Storage Segment			
	Trans Louisiana Gas Pipeline, Inc.	1,000,000	47,500
Total Contracted Storage Capacity		33,425,245	1,135,667

(1) Maximum daily withdrawal quantity (MDWQ) amounts will fluctuate depending upon the season and the month. Unless otherwise noted, MDWQ amounts represent the MDWQ amounts as of November 1, which is the beginning of the winter heating season.

Offices

Our administrative offices and corporate headquarters are consolidated in a leased facility in Dallas, Texas. We also maintain field offices throughout our service territory, some of which are located in leased facilities.

ITEM 3. *Legal Proceedings.*

See Note 11 to the consolidated financial statements, which is incorporated in this Item 3 by reference.

ITEM 4. *Mine Safety Disclosures.*

Not applicable.

PART II

ITEM 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.*

Our stock trades on the New York Stock Exchange under the trading symbol "ATO." The dividends paid per share of our common stock for fiscal 2018 and 2017 are listed below.

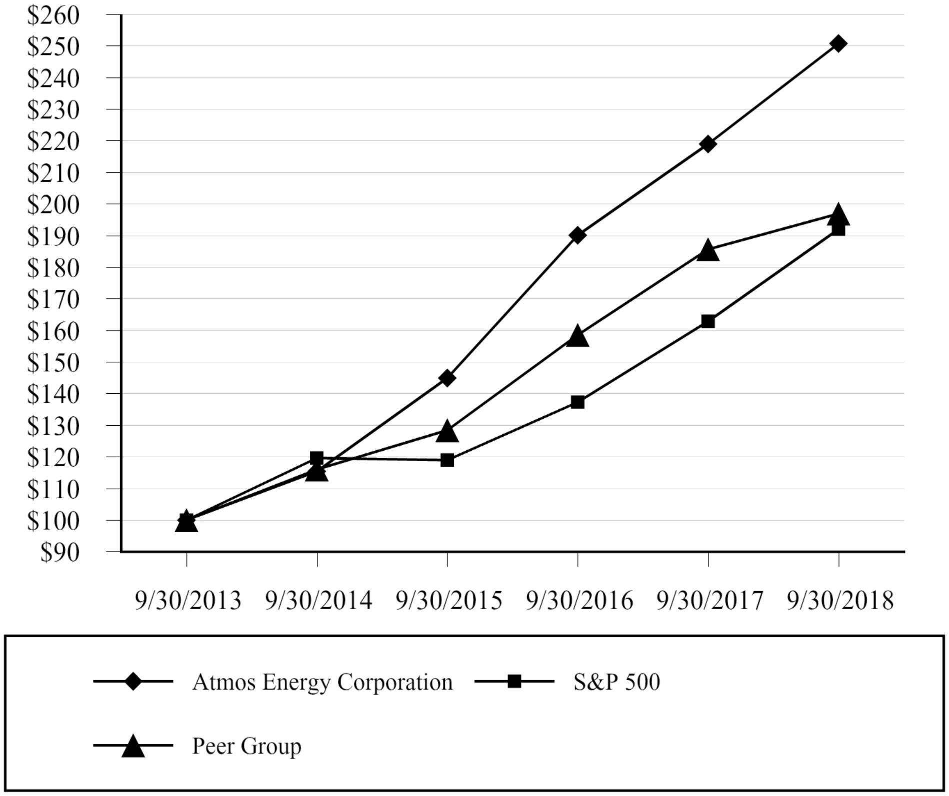
	Fiscal 2018	Fiscal 2017
Quarter ended:		
December 31	$ 0.485	$ 0.450
March 31	0.485	0.450
June 30	0.485	0.450
September 30	0.485	0.450
	$ 1.94	$ 1.80

Dividends are payable at the discretion of our Board of Directors out of legally available funds. The Board of Directors typically declares dividends in the same fiscal quarter in which they are paid. The number of record holders of our common stock on October 31, 2018 was 12,550. Future payments of dividends, and the amounts of these dividends, will depend on our financial condition, results of operations, capital requirements and other factors. We sold no securities during fiscal 2018 that were not registered under the Securities Act of 1933, as amended.

Performance Graph

The performance graph and table below compares the yearly percentage change in our total return to shareholders for the last five fiscal years with the total return of the S&P 500 Stock Index (S&P 500) and the cumulative total return of a customized peer company group, the Comparison Company Index. The Comparison Company Index is comprised of natural gas distribution companies with similar revenues, market capitalizations and asset bases to that of the Company. The graph and table below assume that $100.00 was invested on September 30, 2013 in our common stock, the S&P 500 and in the common stock of the companies in the Comparison Company Indices, as well as a reinvestment of dividends paid on such investments throughout the period.

Comparison of Five-Year Cumulative Total Return among Atmos Energy Corporation, S&P 500 Index and Comparison Company Index



	Cumulative Total Return					
	9/30/2013	9/30/2014	9/30/2015	9/30/2016	9/30/2017	9/30/2018
Atmos Energy Corporation	100.00	115.52	145.03	190.13	218.98	250.80
S&P 500 Stock Index	100.00	119.73	119.00	137.36	162.92	192.10
Peer Group	100.00	116.03	128.49	158.62	185.66	196.95

The Comparison Company Index reflects the cumulative total return of companies in our peer group, which is comprised of a hybrid group of utility companies, primarily natural gas distribution companies, recommended by our independent executive compensation consulting firm and approved by the Board of Directors. The companies in the index are Alliant Energy Corporation, Ameren Corporation, CenterPoint Energy, Inc., CMS Energy Corporation, DTE Energy Company, National Fuel Gas Company, NiSource Inc., ONE Gas, Inc., Spire Inc. (formerly The Laclede Group, Inc.), Vectren Corporation, WEC Energy Group, Inc., WGL Holdings, Inc., and Xcel Energy, Inc.

(1) WGL Holdings Inc. was acquired prior to September 30, 2018. As a result, the cumulative total return of this company is not included in the Comparison Company Index represented in the graph above.

The following table sets forth the number of securities authorized for issuance under our equity compensation plans at September 30, 2018.

	Number of securities to be issued upon exercise of outstanding options, restricted stock units, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders:			
1998 Long-Term Incentive Plan	1,041,519 (1)	$ —	1,752,235
Total equity compensation plans approved by security holders	1,041,519	—	1,752,235
Equity compensation plans not approved by security holders	—	—	—
Total	1,041,519	$ —	1,752,235

(1) Comprised of a total of 422,996 time-lapse restricted stock units, 343,952 director share units and 274,571 performance-based restricted stock units at the target level of performance granted under our 1998 Long-Term Incentive Plan.

ITEM 6. *Selected Financial Data.*

The following table sets forth selected financial data of the Company and should be read in conjunction with the consolidated financial statements included herein.

	Fiscal Year Ended September 30				
	2018	2017	2016	2015	2014
	(In thousands, except per share data)				
Results of Operations					
Operating revenues	$ 3,115,546	$ 2,759,735	$ 2,454,648	$ 2,926,985	$ 3,243,904
Contribution margin	$ 1,947,698	$ 1,834,199	$ 1,708,456	$ 1,631,310	$ 1,521,844
Income from continuing operations	$ 603,064	$ 382,711	$ 345,542	$ 305,623	$ 270,331
Net income	$ 603,064	$ 396,421	$ 350,104	$ 315,075	$ 289,817
Diluted income per share from continuing operations	$ 5.43	$ 3.60	$ 3.33	$ 3.00	$ 2.76
Diluted net income per share	$ 5.43	$ 3.73	$ 3.38	$ 3.09	$ 2.96
Cash dividends declared per share	$ 1.94	$ 1.80	$ 1.68	$ 1.56	$ 1.48
Financial Condition					
Net property, plant and equipment(1)	$ 10,371,147	$ 9,259,182	$ 8,268,606	$ 7,416,700	$ 6,709,926
Total assets	$ 11,874,437	$ 10,749,596	$ 10,010,889	$ 9,075,072	$ 8,581,006
Capitalization:					
Shareholders' equity	$ 4,769,951	$ 3,898,666	$ 3,463,059	$ 3,194,797	$ 3,086,232
Long-term debt (excluding current maturities)	2,493,665	3,067,045	2,188,779	2,437,515	2,442,288
Total capitalization	$ 7,263,616	$ 6,965,711	$ 5,651,838	$ 5,632,312	$ 5,528,520

(1) Amounts shown are net of assets held for sale related to the divestiture of our natural gas marketing business for fiscal years 2014 through 2016.

ITEM 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

INTRODUCTION

This section provides management's discussion of the financial condition, changes in financial condition and results of operations of Atmos Energy Corporation and its consolidated subsidiaries with specific information on results of operations and liquidity and capital resources. It includes management's interpretation of our financial results, the factors affecting these results, the major factors expected to affect future operating results and future investment and financing plans. This discussion should be read in conjunction with our consolidated financial statements and notes thereto.

Several factors exist that could influence our future financial performance, some of which are described in Item 1A above, "Risk Factors". They should be considered in connection with evaluating forward-looking statements contained in this report or otherwise made by or on behalf of us since these factors could cause actual results and conditions to differ materially from those set out in such forward-looking statements.

Cautionary Statement for the Purposes of the Safe Harbor under the Private Securities Litigation Reform Act of 1995

The statements contained in this Annual Report on Form 10-K may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: state and local regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; increased federal regulatory oversight and potential penalties; possible increased federal, state and local regulation of the safety of our operations; the inherent hazards and risks involved in distributing, transporting and storing natural gas; the capital-intensive nature of our business; our ability to continue to access the credit and capital markets to execute our business strategy; market risks beyond our control affecting our risk management activities, including commodity price volatility, counterparty performance or creditworthiness and interest rate risk; the concentration of our operations in Texas; the impact of adverse economic conditions on our customers; changes in the availability and price of natural gas; the availability and accessibility of contracted gas supplies, interstate pipeline and/or storage services; increased competition from energy suppliers and alternative forms of energy; adverse weather conditions; increased costs of providing health care benefits, along with pension and postretirement health care benefits and increased funding requirements; the inability to continue to hire, train and retain operational, technical and managerial personnel; the impact of climate change or related additional legislation or regulation in the future; the threat of cyber-attacks or acts of cyber-terrorism that could disrupt our business operations and information technology systems or result in the loss or exposure of confidential or sensitive customer, employee or Company information; natural disasters, terrorist activities or other events and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

CRITICAL ACCOUNTING POLICIES

Our consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from estimates.

Our significant accounting policies are discussed in Notes 2 and 15 to our consolidated financial statements. The accounting policies discussed below are both important to the presentation of our financial condition and results of operations and require management to make difficult, subjective or complex accounting estimates. Accordingly, these critical accounting policies are reviewed periodically by the Audit Committee of the Board of Directors.

Critical Accounting Policy	Summary of Policy	Factors Influencing Application of the Policy
Regulation	Our distribution and pipeline operations meet the criteria of a cost-based, rate-regulated entity under accounting principles generally accepted in the United States. Accordingly, the financial results for these operations reflect the effects of the ratemaking and accounting practices and policies of the various regulatory commissions to which we are subject. As a result, certain costs that would normally be expensed under accounting principles generally accepted in the United States are permitted to be capitalized or deferred on the balance sheet because it is probable they can be recovered through rates. Further, regulation may impact the period in which revenues or expenses are recognized. The amounts expected to be recovered or recognized are based upon historical experience and our understanding of the regulations. Discontinuing the application of this method of accounting for regulatory assets and liabilities or changes in the accounting for our various regulatory mechanisms could significantly increase our operating expenses as fewer costs would likely be capitalized or deferred on the balance sheet, which could reduce our net income.	Decisions of regulatory authorities Issuance of new regulations or regulatory mechanisms Assessing the probability of the recoverability of deferred costs Continuing to meet the criteria of a cost-based, rate regulated entity for accounting purposes
Unbilled Revenue	We follow the revenue accrual method of accounting for distribution segment revenues whereby revenues attributable to gas delivered to customers, but not yet billed under the cycle billing method, are estimated and accrued and the related costs are charged to expense. When permitted, we implement rates that have not been formally approved by our regulatory authorities, subject to refund.We recognize this revenue and establish a reserve for amounts that could be refunded based on our experience for the jurisdiction in which the rates were implemented.	Estimates of delivered sales volumes based on actual tariff information and weather information and estimates of customer consumption and/or behavior Estimates of purchased gas costs related to estimated deliveries Estimates of amounts billed subject to refund

Critical Accounting Policy	Summary of Policy	Factors Influencing Application of the Policy
Pension and other postretirement plans	Pension and other postretirement plan costs and liabilities are determined on an actuarial basis using a September 30 measurement date and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities. The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligations and net periodic pension and postretirement benefit plan costs. When establishing our discount rate, we consider high quality corporate bond rates based on bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds. The expected long-term rate of return on assets is utilized in calculating the expected return on plan assets component of our annual pension and postretirement plan costs. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater than or less than the assumed rate, that year's annual pension or postretirement plan costs are not affected. Rather, this gain or loss reduces or increases future pension or postretirement plan costs over a period of approximately ten to twelve years. The market-related value of our plan assets represents the fair market value of the plan assets, adjusted to smooth out short-term market fluctuations over a five-year period. The use of this methodology will delay the impact of current market fluctuations on the pension expense for the period. We estimate the assumed health care cost trend rate used in determining our postretirement net expense based upon our actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of retirement is estimated based upon our annual review of our participant census information as of the measurement date.	General economic and market conditions Assumed investment returns by asset class Assumed future salary increases Assumed discount rate Projected timing of future cash disbursements Health care cost experience trends Participant demographic information Actuarial mortality assumptions Impact of legislation Impact of regulation
Impairment assessments	We review the carrying value of our long-lived assets, including goodwill and identifiable intangibles, whenever events or changes in circumstance indicate that such carrying values may not be recoverable, and at least annually for goodwill, as required by U.S. accounting standards. The evaluation of our goodwill balances and other long-lived assets or identifiable assets for which uncertainty exists regarding the recoverability of the carrying value of such assets involves the assessment of future cash flows and external market conditions and other subjective factors that could impact the estimation of future cash flows including, but not limited to the commodity prices, the amount and timing of future cash flows, future growth rates and the discount rate. Unforeseen events and changes in circumstances or market conditions could adversely affect these estimates, which could result in an impairment charge.	General economic and market conditions Projected timing and amount of future discounted cash flows Judgment in the evaluation of relevant data

Non-GAAP Financial Measures

Our operations are affected by the cost of natural gas, which is passed through to our customers without markup and includes commodity price, transportation, storage, injection and withdrawal fees and settlements of financial instruments used to mitigate commodity price risk. These costs are reflected in the income statement as purchased gas cost. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe Contribution Margin, a non-GAAP financial measure, defined as operating revenues less purchased gas cost, is a more useful and relevant measure to analyze our financial performance than operating revenues. As such, the following discussion and analysis of our financial performance will reference Contribution Margin rather than operating revenues and purchased gas cost individually. Further, the term Contribution Margin is not intended to represent operating income, the most comparable GAAP financial measure, as an indicator of operating performance and is not necessarily comparable to similarly titled measures reported by other companies.

As described further in Note 12, the enactment of the Tax Cuts and Jobs Act of 2017 (the "TCJA") required us to remeasure our deferred tax assets and liabilities at our new federal statutory income tax rate as of December 22, 2017. The remeasurement of our net deferred tax liabilities resulted in the recognition of a non-cash income tax benefit of $158.8 million for the fiscal year ended September 30, 2018. Due to the non-recurring nature of this benefit, we believe that income from continuing operations and diluted earnings per share from continuing operations before the non-cash income tax benefit provide a more relevant measure to analyze our financial performance than income from continuing operations and consolidated diluted earnings per share from continuing operations in order to allow investors to better analyze our core results and allow the information to be presented on a comparative basis to the prior year. Accordingly, the following discussion and analysis of our financial performance will reference adjusted income from continuing operations and diluted earnings per share, which is calculated as follows:

	For the Fiscal Year Ended September 30		
	2018	2017	Change
	(In thousands, except per share data)		
Income from continuing operations	$ 603,064	$ 382,711	$ 220,353
TCJA non-cash income tax benefit	(158,782)	—	(158,782)
Adjusted income from continuing operations	$ 444,282	$ 382,711	$ 61,571
Consolidated diluted EPS from continuing operations	$ 5.43	$ 3.60	$ 1.83
Diluted EPS from TCJA non-cash income tax benefit	(1.43)	—	(1.43)
Adjusted diluted EPS from continuing operations	$ 4.00	$ 3.60	$ 0.40

RESULTS OF OPERATIONS

Overview

Atmos Energy strives to operate its businesses safely and reliably while delivering superior shareholder value. Our commitment to modernizing our natural gas distribution and transmission systems requires a significant level of capital spending. We have the ability to begin recovering a significant portion of these investments timely through rate designs and mechanisms that reduce or eliminate regulatory lag and separate the recovery of our approved rate from customer usage patterns. The execution of our capital spending program, the ability to recover these investments timely and our ability to access the capital markets to satisfy our financing needs are the primary drivers that affect our financial performance.

During fiscal 2018, we recorded income from continuing operations of $603.1 million, or $5.43 per diluted share, compared to income from continuing operations of $382.7 million, or $3.60 per diluted share in the prior year.

After adjusting for the nonrecurring benefit recognized after implementing the TCJA, we recognized adjusted income from continuing operations of $444.3 million, or $4.00 per diluted share for the year ended September 30, 2018, compared to adjusted income from continuing operations of $382.7 million, or $3.60 per diluted share for the year ended September 30, 2017. The year-over-year increase of $61.6 million, or 16 percent, largely reflects rate increases driven by safety and reliability spending, weather that was 36 percent colder than the prior year, customer growth in our distribution business and the impact of the TCJA on our effective income tax rate, partially offset by reduced revenues as a result of implementing the TCJA. During the year ended September 30, 2018, we completed 18 regulatory proceedings, resulting in an increase in annual operating income of $80.1 million and had 11 ratemaking efforts in progress at September 30, 2018, seeking a total increase in annual operating income of $52.8 million.

Capital expenditures for fiscal 2018 totaled $1,467.6 million. Over 80 percent was invested to improve the safety and reliability of our distribution and transmission systems, with a significant portion of this investment incurred under regulatory mechanisms that reduce regulatory lag to six months or less. We funded our current-year capital expenditures program primarily through operating cash flows of $1,124.7 million. Additionally, we issued $400 million of common stock during the year ended September 30, 2018. The net proceeds from the issuance were primarily used to repay short-term debt under our commercial paper program, to fund capital spending and for general corporate purposes. On October 4, 2018, we completed a public offering of $600 million 4.30% senior notes due 2048. We received net proceeds from the offering, after underwriting discount and estimated offering expenses of approximately $591 million, that were used to repay working capital borrowings pursuant to our commercial paper program. The effective interest rate of these notes is 4.37% after giving effect to the offering costs.

As a result of the continued contribution and stability of our earnings, cash flows and capital structure, our Board of Directors increased the quarterly dividend by 8.2% percent for fiscal 2019.

TCJA Impact

The TCJA introduced several significant changes to corporate income tax laws in the United States, which have been reflected in our consolidated financial statements for the year ended September 30, 2018. As a rate regulated entity, the effects of lower tax rates included in our cost of service rates will ultimately flow through to our utility customers in the form of adjusted rates. Therefore, the favorable impact of the reduction in our federal statutory income tax rate on our financial performance will be limited to items that impact our income before income taxes in the current period that have not yet been reflected in our rates (most notably increases to and decreases in commission-approved regulatory assets and liabilities recorded on our consolidated balance sheet) and market-based revenues that are earned from customers who utilize our assets. Note 12 to the consolidated financial statements details the various impacts of the TCJA on our financial position and results from operations. The most significant changes are summarized as follows:

- Because our fiscal year started on October 1, 2017, our federal statutory income tax rate for fiscal 2018 was reduced from 35% to 24.5%. Our effective income tax rate for fiscal 2018 was 27.5%, before the effect of the return of the excess deferred tax liability and the one-time, non-cash income tax benefit. Our federal statutory income tax rate declined to 21% on October 1, 2018.
- As a result of implementing the TCJA, we remeasured our net deferred tax liability using our new federal statutory income tax rate, which reduced our net deferred tax liability by $905.3 million. Of this amount, $746.5 million was reclassified to a regulatory liability called excess deferred tax liability. The remaining $158.8 million was recognized as a one-time, non-cash income tax benefit in our consolidated statement of income for the year ended September 30, 2018.
- Atmos Energy supports our regulators' efforts to ensure our utility customers receive the full benefits of changes in our cost of service rates arising from tax reform. Income taxes, like other costs, are passed through to our customers in our rates; however, changes to customer rates must be approved by our regulators.
  - Beginning in the second quarter of fiscal 2018, we established regulatory liabilities in all our jurisdictions for the difference in taxes included in our cost of service rates that have been calculated based on a 35% statutory income tax rate and a 21% statutory income tax rate, which reduced our revenues. We have received approval from most of our regulators to adjust customer rates for the lower statutory income tax rate.
  - We have also received approval from regulators in several of our states to return amounts to customers related to the regulatory liability recorded for differences in our cost of service rates due to the change in the statutory income tax rate within one year.
  - We have received approval from regulators in several of our states to begin returning the Excess Deferred Tax Liability created upon implementation of the TCJA, as discussed above, over a period ranging from 18 to 40 years. For the year ended September 30, 2018, we amortized $1.6 million of this regulatory liability.
- The enactment of the TCJA is expected to reduce our future cash flows from operations primarily due to 1) the collection of taxes at a lower rate and 2) the return of regulatory liabilities established in response to the enactment of the TCJA and regulatory activities to our utility customers. We intend to externally finance this reduction in operating cash flow in a balanced fashion in order to maintain an equity-to-total-capitalization ratio ranging from 50% to 60% to maintain our current credit ratings.

Consolidated Results

The following table presents our consolidated financial highlights for the fiscal years ended September 30, 2018, 2017 and 2016.

	For the Fiscal Year Ended September 30		
	2018	2017	2016
	(In thousands, except per share data)		
Operating revenues	$ 3,115,546	$ 2,759,735	$ 2,454,648
Purchased gas cost	1,167,848	925,536	746,192
Operating expenses	1,224,564	1,106,653	1,051,226
Operating income	723,134	727,546	657,230
Interest charges	106,646	120,182	114,812
Income from continuing operations before income taxes	611,144	604,094	542,184
Income tax expense	166,862	221,383	196,642
One-time, non-cash income tax benefit	(158,782)	—	—
Net income from continuing operations	603,064	382,711	345,542
Net income from discontinued operations	—	13,710	4,562
Net income	$ 603,064	$ 396,421	$ 350,104
Diluted net income from continuing operations per share	$ 5.43	$ 3.60	$ 3.33
Diluted net income from discontinued operations per share	—	0.13	0.05
Diluted net income per share	$ 5.43	$ 3.73	$ 3.38

Our consolidated net income during the last three fiscal years was earned across our business segments as follows:

	For the Fiscal Year Ended September 30		
	2018	2017	2016
	(In thousands)		
Distribution segment	$ 442,966	$ 268,369	$ 233,830
Pipeline and storage segment	160,098	114,342	111,712
Net income from continuing operations	603,064	382,711	345,542
Net income from discontinued natural gas marketing operations	—	13,710	4,562
Net income	$ 603,064	$ 396,421	$ 350,104

See the following discussion regarding the results of operations for each of our business operating segments.

Distribution Segment

The distribution segment is primarily comprised of our regulated natural gas distribution and related sales operations in eight states. The primary factors that impact the results of our distribution operations are our ability to earn our authorized rates of return, competitive factors in the energy industry and economic conditions in our service areas.

Our ability to earn our authorized rates is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions to minimize regulatory lag and, ultimately, separate the recovery of our approved rates from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions. The “Ratemaking Activity” section of this Form 10-K describes our current rate strategy, progress towards implementing that strategy and recent ratemaking initiatives in more detail.

We are generally able to pass the cost of gas through to our customers without markup under purchased gas cost adjustment mechanisms; therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Contribution margin in our Texas and Mississippi service areas include franchise fees and gross receipt taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenue is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in revenue related taxes arising from changes in gas costs affect Contribution Margin, over time the impact is offset within operating income.

Although the cost of gas typically does not have a direct impact on our Contribution Margin, higher gas costs may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. In addition, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or, in the case of industrial consumers, to use alternative energy sources. Currently, gas cost risk has been mitigated by rate design that allows us to collect from our customers the gas cost portion of our bad debt expense on approximately 76 percent of our residential and commercial margins.

During fiscal 2018, we completed 16 regulatory proceedings in our distribution segment, resulting in an $8.9 million increase in annual operating income.

Review of Financial and Operating Results

Financial and operational highlights for our distribution segment for the fiscal years ended September 30, 2018, 2017 and 2016 are presented below.

	For the Fiscal Year Ended September 30				
	2018	2017	2016	2018 vs. 2017	2017 vs. 2016
	(In thousands, unless otherwise noted)				
Operating revenues	$ 3,003,047	$ 2,649,175	$ 2,339,778	$ 353,872	$ 309,397
Purchased gas cost	1,559,836	1,269,456	1,058,576	290,380	210,880
Contribution Margin	1,443,211	1,379,719	1,281,202	63,492	98,517
Operating expenses	962,344	874,077	839,318	88,267	34,759
Operating income	480,867	505,642	441,884	(24,775)	63,758
Miscellaneous income (expense)	(1,849)	(1,695)	1,171	(154)	(2,866)
Interest charges	65,850	79,789	78,238	(13,939)	1,551
Income before income taxes	413,168	424,158	364,817	(10,990)	59,341
Income tax expense	107,880	155,789	130,987	(47,909)	24,802
One-time, non-cash income tax benefit	(137,678)	—	—	(137,678)	—
Net income	$ 442,966	$ 268,369	$ 233,830	$ 174,597	$ 34,539
Consolidated distribution sales volumes — MMcf	300,817	246,825	258,650	53,992	(11,825)
Consolidated distribution transportation volumes — MMcf	150,566	141,540	133,378	9,026	8,162
Total consolidated distribution throughput — MMcf	451,383	388,365	392,028	63,018	(3,663)
Consolidated distribution average cost of gas per Mcf sold	$ 5.19	$ 5.14	$ 4.09	$ 0.05	$ 1.05

Fiscal year ended September 30, 2018 compared with fiscal year ended September 30, 2017

Income before income taxes for our distribution segment decreased three percent, primarily due to an $88.3 million increase in operating expenses, partially offset by a $63.5 million increase in Contribution Margin. The year-to-date increase in Contribution Margin primarily reflects:

- a $70.7 million net increase in rate adjustments, excluding rate adjustments resulting from the TCJA, primarily in our Mid-Tex, Kentucky/Mid-States, Mississippi and West Texas Divisions. These rate adjustments were driven primarily by increased safety and reliability spending.
- a $12.2 million increase in net consumption, primarily in our Mid-Tex, Mississippi, Kentucky/Mid-States and Louisiana Divisions.
- a $14.8 million increase in revenue-related taxes primarily in our Mid-Tex Division, offset by a corresponding $15.5 million increase in the related tax expense.
- an $8.9 million increase in transportation margin primarily in our Kentucky/Mid-States Division.
- an $8.4 million increase from customer growth, primarily in our Mid-Tex Division.

- a $51.3 million decrease in Contribution Margin due to the inclusion of the lower statutory federal income tax rate in our revenues due to implementation of the TCJA. Of this amount, $30.0 million has been reflected in customer bills. The remaining $21.3 million relates to the establishment of regulatory liabilities for the difference between the former 35% federal statutory income tax rate and the current 21% rate.

The increase in operating expenses, which include operation and maintenance expense, bad debt expense, depreciation and amortization expense and taxes, other than income, largely reflects expenses incurred after we decided to undertake a planned outage of our natural gas distribution system in Northwest Dallas that affected approximately 2,400 homes. While the system was replaced, we provided financial assistance to the affected residents and incurred other related costs of approximately $24 million.

The remaining increase in operating expenses is primarily attributable to an increase in employee-related costs and incremental system integrity activities of $19.3 million, increased revenue-related taxes, as discussed above, and increased depreciation and property taxes of $22.5 million associated with increased capital investments.

Interest charges decreased $13.9 million, primarily from interest deferrals associated with our infrastructure spending activities in Texas and Louisiana.

The decrease in income tax expense primarily reflects a reduction in our effective tax rate from 36.7% to 26.1%, as a result of the TCJA. During fiscal 2018, in certain jurisdictions, we began amortizing the excess deferred income taxes in the amount of $1.6 million.

Fiscal year ended September 30, 2017 compared with fiscal year ended September 30, 2016

Income before income taxes for our distribution segment increased 16 percent, primarily due to a $98.5 million increase in Contribution Margin, partially offset by a $34.8 million increase in operating expenses. The year-over-year increase in Contribution Margin primarily reflects:

- a $72.4 million net increase in rate adjustments, primarily in our Mid-Tex, Louisiana, Mississippi and West Texas Divisions. These rate adjustments were driven primarily by increased safety and reliability spending.
- Customer growth, primarily in our Mid-Tex and Kentucky/Mid-States Divisions, which contributed an incremental $5.8 million.
- a $5.8 million increase in transportation margin, primarily in the Kentucky/Mid-States and Mid-Tex Divisions.
- a $5.2 million increase in revenue-related taxes primarily in our Mid-Tex and West Texas Divisions, offset by a corresponding $5.1 million increase in the related tax expense.
- a $2.9 million increase in net consumption, despite weather that was 12 percent warmer than the prior year.

The increase in operating expenses was primarily due to increased depreciation expense and property taxes associated with increased capital investments, higher employee-related costs, increased revenue-related taxes, as discussed above, and higher pipeline maintenance and related activities, partially offset by lower legal costs.

The following table shows our operating income by distribution division, in order of total rate base, for the fiscal years ended September 30, 2018, 2017 and 2016. The presentation of our distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	For the Fiscal Year Ended September 30				
	2018	2017	2016	2018 vs. 2017	2017 vs. 2016
			(In thousands)		
Mid-Tex	$ 202,444	$ 233,158	$ 210,608	$ (30,714)	$ 22,550
Kentucky/Mid-States	81,105	75,214	63,730	5,891	11,484
Louisiana	70,609	69,300	55,857	1,309	13,443
West Texas	45,494	46,859	41,131	(1,365)	5,728
Mississippi	47,237	38,505	37,398	8,732	1,107
Colorado-Kansas	32,333	34,658	31,840	(2,325)	2,818
Other	1,645	7,948	1,320	(6,303)	6,628
Total	$ 480,867	$ 505,642	$ 441,884	$ (24,775)	$ 63,758

Pipeline and Storage Segment

Our pipeline and storage segment consists of the pipeline and storage operations of Atmos Pipeline-Texas Division (APT) and our natural gas transmission operations in Louisiana. APT is one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Barnett Shale, the Texas Gulf Coast and the Delaware and Midland Basins of West Texas. APT provides transportation and storage services to our Mid-Tex Division, other third party local distribution companies, industrial and electric generation customers, as well as marketers and producers. As part of its pipeline operations, APT owns and operates five underground storage facilities in Texas.

Our natural gas transmission operations in Louisiana are comprised of a proprietary 21-mile pipeline located in the New Orleans, Louisiana area that is primarily used to aggregate gas supply for our distribution division in Louisiana under a long-term contract and, on a more limited basis, to third parties. The demand fee charged to our Louisiana distribution division for these services is subject to regulatory approval by the Louisiana Public Service Commission. We also manage two asset management plans, which have been approved by applicable state regulatory commissions. Generally, these asset management plans require us to share with our distribution customers a significant portion of the cost savings earned from these arrangements.

Our pipeline and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our Texas and Louisiana service areas. Natural gas prices do not directly impact the results of this segment as revenues are derived from the transportation and storage of natural gas. However, natural gas prices and demand for natural gas could influence the level of drilling activity in the supply areas that we serve, which may influence the level of throughput we may be able to transport on our pipelines. Further, natural gas price differences between the various hubs that we serve in Texas could influences the volumes of gas transported for shippers through Texas pipeline systems and rates for such transportation.

The results of APT are also significantly impacted by the natural gas requirements of its local distribution company customers. Additionally, its operations may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

APT annually uses the Gas Reliability Infrastructure Program (GRIP) to recover capital costs incurred in the prior calendar year. Following the conclusion of its rate case in August 2017, APT made a GRIP filing that covered changes in net investment from October 1, 2016 through December 31, 2016 with a requested increase in operating income of $29.0 million. On December 5, 2017, the filing was approved. On February 15, 2018, APT made a GRIP filing that covered changes in net investment from January 1, 2017 through December 31, 2017 with a requested increase in operating income of $42.2 million. On May 22, 2018, the filing was approved.

On December 21, 2016, the Louisiana Public Service Commission approved an annual increase of five percent to the demand fee charged by our natural gas transmission pipeline for each of the next 10 years, effective October 1, 2017.

Review of Financial and Operating Results

Financial and operational highlights for our pipeline and storage segment for the fiscal years ended September 30, 2018, 2017 and 2016 are presented below.

	For the Fiscal Year Ended September 30				
	2018	2017	2016	2018 vs. 2017	2017 vs. 2016
	(In thousands, unless otherwise noted)				
Mid-Tex / Affiliate transportation revenue	$ 354,885	$ 338,850	$ 315,726	$ 16,035	$ 23,124
Third-party transportation revenue	140,231	100,100	89,498	40,131	10,602
Other revenue	12,597	18,080	21,972	(5,483)	(3,892)
Total operating revenues	507,713	457,030	427,196	50,683	29,834
Total purchased gas cost	1,978	2,506	(58)	(528)	2,564
Contribution Margin	505,735	454,524	427,254	51,211	27,270
Operating expenses	263,468	232,620	211,908	30,848	20,712
Operating income	242,267	221,904	215,346	20,363	6,558
Miscellaneous expense	(3,495)	(1,575)	(1,405)	(1,920)	(170)
Interest charges	40,796	40,393	36,574	403	3,819
Income before income taxes	197,976	179,936	177,367	18,040	2,569
Income tax expense	58,982	65,594	65,655	(6,612)	(61)
One-time, non-cash income tax benefit	(21,104)	—	—	(21,104)	—
Net income	$ 160,098	$ 114,342	$ 111,712	$ 45,756	$ 2,630
Gross pipeline transportation volumes — MMcf	871,904	770,348	686,042	101,556	84,306
Consolidated pipeline transportation volumes — MMcf	663,900	596,179	505,303	67,721	90,876

Fiscal year ended September 30, 2018 compared with fiscal year ended September 30, 2017

Income before income taxes for our pipeline and storage segment increased ten percent, primarily due to a $51.2 million increase in Contribution Margin, partially offset by a $30.8 million increase in operating expenses. The increase in Contribution Margin primarily reflects:

- a $74.3 million increase in rates from the approved APT rate case and the GRIP filings approved in December 2017 and May 2018. The increase in rates was driven primarily by increased safety and reliability spending.
- a net increase of $1.3 million due to wider spreads and positive supply and demand dynamics affecting the Permian Basin.
- a $24.1 million decrease in Contribution Margin due to the inclusion of the lower statutory federal income tax rate in our revenues due to implementation of the TCJA. Of this amount, $11.4 million has been reflected in customer bills. The remaining $12.7 million relates to the establishment of regulatory liabilities, as discussed above.

The increase in operating expenses is primarily due to higher depreciation expense of $25.8 million associated with increased capital investments and an increase in employee-related costs.

The decrease in income tax expense primarily reflects a reduction in our effective tax rate from 36.5% to 29.8%, as a result of the TCJA.

Fiscal year ended September 30, 2017 compared with fiscal year ended September 30, 2016

Income before income taxes for our pipeline and storage segment increased slightly, primarily due to a $27.3 million increase in Contribution Margin, partially offset by a $20.7 million increase in operating expenses. The increase in Contribution Margin primarily reflects a $24.6 million increase in rates from the approved 2016 GRIP filing and the rate case finalized in August 2017 and higher through system revenue of $8.3 million, largely related to higher basis spreads due to increased production in the Permian Basin and incremental throughput on a pipeline acquired in the first quarter of fiscal 2017. Partially offsetting these increases was a decrease in Contribution Margin of $2.3 million due to lower excess retention gas sales in the current year. As noted above, as a result of the annual rate case, we did not file our annual GRIP filing during the second quarter of fiscal 2017, which influenced this segment's performance year-over-year.

Operating expenses increased $20.7 million, primarily due to increased depreciation expense and property taxes associated with increased capital investments.

Natural Gas Marketing Segment

Through December 31, 2016, we were engaged in an unregulated natural gas marketing business, which was conducted by Atmos Energy Marketing (AEM). AEM's primary business was to aggregate and purchase gas supply, arrange transportation and storage logistics and ultimately deliver gas to customers at competitive prices.

As more fully described in Note 15, effective January 1, 2017, we sold all of the equity interests of AEM to CenterPoint Energy Services, Inc. (CES), a subsidiary of CenterPoint Energy Inc. As a result of the sale, Atmos Energy has fully exited the nonregulated natural gas marketing business. Accordingly, a gain on sale from discontinued operations for $2.7 million was recorded and net income of $11.0 million for AEM is reported as discontinued operations for the year ended September 30, 2017, compared to net income of $4.6 million for AEM reported for discontinued operations for the year ended September 30, 2016.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas marketing segment for the fiscal years ended September 30, 2017 and 2016 are presented below.

	For the Fiscal Year Ended September 30		
	2017	2016	2017 vs. 2016
	(In thousands, unless otherwise noted)		
Operating revenues	$ 303,474	$ 1,005,090	$ (701,616)
Purchased gas cost	277,554	968,118	(690,564)
Contribution Margin	25,920	36,972	(11,052)
Operating expenses	7,874	26,184	(18,310)
Operating income	18,046	10,788	7,258
Miscellaneous income	30	109	(79)
Interest charges	241	2,604	(2,363)
Income before income taxes	17,835	8,293	9,542
Income tax expense	6,841	3,731	3,110
Income from discontinued operations	10,994	4,562	6,432
Gain on sale of discontinued operations, net of tax	2,716	—	2,716
Net income from discontinued operations	$ 13,710	$ 4,562	$ 9,148
Gross natural gas marketing delivered gas sales volumes — MMcf	90,223	371,319	(281,096)
Consolidated natural gas marketing delivered gas sales volumes — MMcf	78,646	325,537	(246,891)
Net physical position (Bcf)	—	18.1	(18.1)

Fiscal year ended September 30, 2017 compared with fiscal year ended September 30, 2016

The $9.1 million year-over-year increase in net income from discontinued operations primarily reflects the recognition of a net $6.6 million noncash gain from unwinding hedge accounting for certain of the natural gas marketing business's financial positions in connection with the sale of AEM. Additionally we recognized a $2.7 million net gain on sale upon completion of the sale of AEM to CES in January 2017.

LIQUIDITY AND CAPITAL RESOURCES

The liquidity required to fund our working capital, capital expenditures and other cash needs is provided from a combination of internally generated cash flows and external debt and equity financing. External debt financing is provided primarily through the issuance of long-term debt, a $1.5 billion commercial paper program and three committed revolving credit facilities with a total availability from third-party lenders of approximately $1.5 billion. The commercial paper program and credit facilities provide cost-effective, short-term financing until it can be replaced with a balance of long-term debt and equity financing that achieves the Company's desired capital structure with an equity-to-total-capitalization ratio between 50% and 60%, inclusive of long-term and short-term debt. Additionally, we have various uncommitted trade credit lines with our gas suppliers that we utilize to purchase natural gas on a monthly basis. The liquidity provided by these sources is expected to be sufficient to fund the Company's working capital needs and capital expenditures program for fiscal year 2019 and beyond. Please refer to the *TCJA Impact* section above regarding anticipated impacts on our liquidity, capital resources and cash flows.

To support our capital market activities, we have a registration statement on file with the SEC that permits us to issue a total of $2.5 billion in common stock and/or debt securities. The shelf registration statement expires on March 26, 2019. Under the shelf registration statement, in November 2017, we filed a prospectus supplement for an at-the-market (ATM) equity distribution program under which we may issue and sell shares of our common stock up to an aggregate offering price of $500 million.

At September 30, 2018, approximately $650.0 million of securities remained available for issuance under the shelf registration statement. On October 4, 2018, we completed a public offering of $600 million of 4.30% senior notes due 2048. The effective rate of this note is 4.37% after giving effect to the offering costs. We received net proceeds from the offering, after underwriting discount and estimated offering expenses of approximately $591 million, that were used to repay working capital borrowings pursuant to our commercial paper program. The issuance of these notes effectively exhausted our existing shelf registration statement.

During the first quarter of fiscal 2019, we intend to file a new registration statement for the issuance, from time to time, of up to $3.0 billion in common stock and/or debt securities In addition, during the first quarter of fiscal 2019, we plan to enter into a new ATM equity distribution agreement under which we may issue and sell shares of our common stock, up to an aggregate offering price of $500 million, under the new shelf registration statement.

The following table presents our capitalization as of September 30, 2018 and 2017:

	September 30			
	2018		2017	
	(In thousands, except percentages)			
Short-term debt	$ 575,780	6.8%	$ 447,745	6.0%
Long-term debt	3,068,665	36.5%	3,067,045	41.4%
Shareholders’ equity	4,769,951	56.7%	3,898,666	52.6%
Total capitalization, including short-term debt	$ 8,414,396	100.0%	$ 7,413,456	100.0%

Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These factors include regulatory changes, the price for our services, the demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

Cash flows from operating, investing and financing activities for the years ended September 30, 2018, 2017 and 2016 are presented below.

	For the Fiscal Year Ended September 30				
	2018	2017	2016	2018 vs. 2017	2017 vs. 2016
	(In thousands)				
Total cash provided by (used in)					
Operating activities	$ 1,124,662	$ 867,090	$ 794,990	$ 257,572	$ 72,100
Investing activities	(1,463,566)	(1,056,306)	(1,079,732)	(407,260)	23,426
Financing activities	326,266	168,091	303,623	158,175	(135,532)
Change in cash and cash equivalents	(12,638)	(21,125)	18,881	8,487	(40,006)
Cash and cash equivalents at beginning of period	26,409	47,534	28,653	(21,125)	18,881
Cash and cash equivalents at end of period	$ 13,771	$ 26,409	$ 47,534	$ (12,638)	$ (21,125)

Cash flows from operating activities

Year-over-year changes in our operating cash flows primarily are attributable to changes in net income and working capital changes, particularly within our distribution segment resulting from changes in the price of natural gas and the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.

Fiscal Year ended September 30, 2018 compared with fiscal year ended September 30, 2017

For the fiscal year ended September 30, 2018, we generated operating cash flows of $1,124.7 million compared with $867.1 million in the prior year. The year-over-year increase primarily reflects the positive cash effects of successful rate case outcomes achieved in fiscal 2017 driven primarily by increased safety and reliability spending and changes in working capital, primarily as a result of the timing of gas cost recoveries under our purchase gas cost mechanisms as a result of a year-over-year increase in sale volumes. This increase in sales volumes also contributed to the year-over-year increase in operating cash flow.

Fiscal Year ended September 30, 2017 compared with fiscal year ended September 30, 2016

For the fiscal year ended September 30, 2017, we generated operating cash flows of $867.1 million compared with $795.0 million in fiscal 2016. The year-over-year increase primarily reflects the positive cash effect of successful rate case outcomes achieved in fiscal 2016.

Cash flows from investing activities

In recent years, we have used substantial amounts of cash to fund our ongoing construction program, which enables us to improve safety and reliability by modernizing our distribution and transmission system, used to provide distribution services to our existing customer base, expand our natural gas distribution services into new markets, enhance the integrity of our pipelines and, more recently, expand our intrastate pipeline network. Over the last three fiscal years, approximately 82 percent of our capital spending has been committed to improving the safety and reliability of our system.

In executing our regulatory strategy, we target our capital spending on regulatory mechanisms that permit us to earn an adequate return timely on our investment without compromising the safety or reliability of our system. Substantially all of our regulated jurisdictions have rate tariffs that provide the opportunity to include in their rate base approved capital costs on a periodic basis without being required to file a rate case.

For the fiscal year ended September 30, 2018, we had $1,467.6 million in capital expenditures compared with $1,137.1 million for the fiscal year ended September 30, 2017 and $1,087.0 million for the fiscal year ended September 30, 2016.

Fiscal Year ended September 30, 2018 compared with fiscal year ended September 30, 2017

The $330.5 million increase in capital expenditures in fiscal 2018 compared to fiscal 2017 primarily reflects planned increases to modernize our distribution and transmission system, and increases in spending in our pipeline and storage segment to improve the reliability of gas service to our local distribution company customers. The year-over-year increase also reflects the absence in the current year period of $140.3 million in net proceeds received from the sale of AEM, $29.8 million in proceeds received from the completion of a State of Texas use tax audit and the $86.1 million used to acquire a pipeline in December 2016.

Fiscal Year ended September 30, 2017 compared with fiscal year ended September 30, 2016

The $50.1 million increase in capital expenditures in fiscal 2017 compared to fiscal 2016 primarily reflects a:

- $109.7 million increase due to planned increases in our distribution segment to replace vintage pipe.
- $59.2 million decrease in spending in our pipeline and storage segment as a result of the substantial completion of an APT project to improve the reliability of gas service to its local distribution company customers.

Cash flows from investing activities for the year ended September 30, 2017 also include proceeds of $140.3 million received from the sale of AEM, proceeds received from the completion of a State of Texas use tax audit and $86.1 million used to purchase a pipeline in the first fiscal quarter of 2017.

Cash flows from financing activities

We generated a net amount of $326.3 million, $168.1 million and $303.6 million in cash from financing activities for fiscal years 2018, 2017 and 2016. Our significant financing activities for the fiscal years ended September 30, 2018, 2017 and 2016 are summarized as follows:

2018

During the fiscal year ended September 30, 2018, our financing activities generated $326.3 million of cash compared with $168.1 million of cash generated in the prior year. The $158.2 million increase in cash provided by financing activities reflects higher net short-term borrowings due to increased capital expenditures and period-over-period changes in working capital funding needs compared to the prior year, as well as net proceeds received of $395.1 million from equity financing. Cash dividends increased due to a 7.8% increase in our dividend rate and an increase in shares outstanding.

2017

During the fiscal year ended September 30, 2017, our financing activities generated $168.1 million of cash compared with $303.6 million of cash generated in the prior year. The $135.5 million decrease in cash provided by financing activities is primarily due to the reduction in our short–term debt, partially offset by an increase in our long-term debt.

During fiscal 2017, we completed approximately $975 million of debt and equity financing. On June 8, 2017, we completed a public offering of $500 million of 3.00% senior unsecured notes due 2027 and $250 million of 4.125% senior unsecured notes due 2044. The net proceeds of approximately $753 million were used to repay our $250 million 6.35% senior unsecured notes at maturity on June 15, 2017 and for general corporate purposes, including the repayment of working capital borrowings pursuant to our commercial paper program. In October 2016, we issued $125 million of long-term debt under our three year, $200 million multi-draw term loan agreement.

Additionally, during fiscal 2017 we issued 1.3 million shares under our ATM program and received net proceeds of $98.8 million. As of September 30, 2017, substantially all of shares under this program had been issued.

2016

During the fiscal year ended September 30, 2016, our financing activities generated $303.6 million of cash compared with $131.1 million of cash generated in fiscal 2015. The increase is primarily due to higher net short-term borrowings due to increased capital expenditures and period-over-period changes in working capital funding needs compared to the prior year, as well as proceeds received from the issuance of common stock under our ATM program in the third fiscal quarter of 2016.

The following table shows the number of shares issued for the fiscal years ended September 30, 2018, 2017 and 2016:

	For the Fiscal Year Ended September 30		
	2018	**2017**	**2016**
Shares issued:			
Direct Stock Purchase Plan	131,213	112,592	133,133
Retirement Savings Plan	94,081	228,326	359,414
1998 Long-Term Incentive Plan (LTIP)	385,351	529,662	598,439
November 2017 Offering	4,558,404	—	—
At-the-Market (ATM) Equity Sales Program	—	1,303,494	1,360,756
Total shares issued	5,169,049	2,174,074	2,451,742

Credit Ratings

Our credit ratings directly affect our ability to obtain short-term and long-term financing, in addition to the cost of such financing. In determining our credit ratings, the rating agencies consider a number of quantitative factors, including debt to total capitalization, operating cash flow relative to outstanding debt, operating cash flow coverage of interest and pension liabilities and funding status. In addition, the rating agencies consider qualitative factors such as consistency of our earnings over time, the quality of our management and business strategy and the regulatory environment in the states where we operate.

Our debt is rated by two rating agencies: Standard & Poor’s Corporation (S&P) and Moody’s Investors Service (Moody’s). As of September 30, 2018, both rating agencies maintained a stable outlook.

Our current debt ratings are all considered investment grade and are as follows:

	S&P	**Moody’s**
Senior unsecured long-term debt	A	A2
Short-term debt	A-1	P-1

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of deteriorating global or national financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the two credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating is AAA for S&P and Aaa for Moody’s. The lowest investment grade credit rating is BBB- for S&P and Baa3 for Moody’s. Our credit ratings may be revised or withdrawn at any time by the rating agencies, and each rating should be evaluated independently of any other rating. There can be no assurance that a rating will remain in effect for any given period of time or that a rating will not be lowered, or withdrawn entirely, by a rating agency if, in its judgment, circumstances so warrant.

Debt Covenants

We were in compliance with all of our debt covenants as of September 30, 2018. Our debt covenants are described in Note 5 to the consolidated financial statements.

Contractual Obligations and Commercial Commitments

The following table provides information about contractual obligations and commercial commitments at September 30, 2018.

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(In thousands)		
Contractual Obligations					
Long-term debt[1]	$ 3,085,000	$ 575,000	$ —	$ —	$ 2,510,000
Short-term debt[1]	575,780	575,780	—	—	—
Interest charges[2]	2,257,307	134,227	222,759	222,759	1,677,562
Operating leases[3]	104,191	17,655	32,685	31,625	22,226
Financial instrument obligations[4]	56,837	56,734	103	—	—
Pension and postretirement benefit plan contributions[5]	275,907	24,882	56,310	63,525	131,190
Uncertain tax positions [6]	26,203	—	26,203	—	—
Total contractual obligations	$ 6,381,225	$ 1,384,278	$ 338,060	$ 317,909	$ 4,340,978

(1) See Note 5 to the consolidated financial statements.
(2) Interest charges were calculated using the effective rate for each debt issuance.
(3) See Note 10 to the consolidated financial statements.
(4) Represents liabilities for natural gas commodity and interest rate financial instruments that were valued as of September 30, 2018. The ultimate settlement amounts of these remaining liabilities are unknown because they are subject to continuing market risk until the financial instruments are settled.
(5) Represents expected contributions to our pension and postretirement benefit plans, which are discussed in Note 7 to the consolidated financial statements.
(6) Represents liabilities associated with uncertain tax positions claimed or expected to be claimed on tax returns. The amount does not include interest and penalties that may be applied to these positions.

We maintain supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of individual contracts. Our Mid-Tex Division also maintains a limited number of long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market and fixed prices. At September 30, 2018, we were committed to purchase 54.1 Bcf within one year and 37.2 Bcf within two to three years under indexed contracts.

The passage of the TCJA resulted in the remeasurement of our net deferred tax liability. At September 30, 2018, we recorded $744.9 million, which relates to our regulated operations and has been recorded as a regulatory liability. The period and timing of the return of the excess deferred taxes is being determined by regulators in each of our jurisdictions. See Note 12 for further information.

Risk Management Activities

We use financial instruments to mitigate commodity price risk and, periodically, to manage interest rate risk. In our distribution and pipeline and storage segments, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases. Additionally, we manage interest rate risk by entering into financial instruments to effectively fix the Treasury yield component of the interest cost associated with anticipated financings.

We record our financial instruments as a component of risk management assets and liabilities, which are classified as current or noncurrent based upon the anticipated settlement date of the underlying financial instrument. Substantially all of our financial instruments are valued using external market quotes and indices.

The following table shows the components of the change in fair value of our financial instruments for the fiscal year ended September 30, 2018 (in thousands):

Fair value of contracts at September 30, 2017	$ (109,159)
Contracts realized/settled	(1,254)
Fair value of new contracts	241
Other changes in value	54,954
Fair value of contracts at September 30, 2018	(55,218)
Netting of cash collateral	—
Cash collateral and fair value of contracts at September 30, 2018	$ (55,218)

The fair value of our financial instruments at September 30, 2018, is presented below by time period and fair value source:

	Fair Value of Contracts at September 30, 2018				
	Maturity in years				
Source of Fair Value	Less than 1	1-3	4-5	Greater than 5	Total Fair Value
			(In thousands)		
Prices actively quoted	$ (55,365)	$ 147	$ —	$ —	$ (55,218)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ (55,365)	$ 147	$ —	$ —	$ (55,218)

Employee Benefits Programs

An important element of our total compensation program, and a significant component of our operation and maintenance expense, is the offering of various benefits programs to our employees. These programs include medical and dental insurance coverage and pension and postretirement programs.

Medical and Dental Insurance

We offer medical and dental insurance programs to substantially all of our employees. We believe these programs are compliant with all current regulatory provisions and are consistent with other programs in our industry. In recent years, we have endeavored to actively manage our health care costs through the introduction of a wellness strategy that is focused on helping employees to identify health risks and to manage these risks through improved lifestyle choices.

Over the last five fiscal years, we have experienced annual medical and prescription inflation of approximately seven percent. For fiscal 2019, we anticipate the medical and prescription drug inflation rate will increase at approximately six percent, primarily due to the inflation of health care costs and normalization of large claim activity.

Net Periodic Pension and Postretirement Benefit Costs

For the fiscal year ended September 30, 2018, our total net periodic pension and other benefits costs was $41.4 million, compared with $49.0 million and $46.0 million for the fiscal years ended September 30, 2017 and 2016. These costs are recoverable through our rates. A portion of these costs is capitalized into our distribution rate base and the remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2018 costs were determined using a September 30, 2017 measurement date. At that date, interest and corporate bond rates utilized to determine our discount rates were higher than the interest and corporate bond rates as of September 30, 2016, the measurement date for our fiscal 2017 net periodic cost. Therefore, we increased the discount rate used to measure our fiscal 2018 net periodic cost from 3.73 percent to 3.89 percent. We lowered the expected return on plan assets from 7.00 percent to 6.75 percent in the determination of our fiscal 2018 net periodic pension cost based upon expected market returns for our targeted asset allocation. On October 20, 2017, the Society of Actuaries released its annually-updated mortality improvement scale for pension plans incorporating new assumptions surrounding life expectancies in the United States. As of September 30, 2017, we updated our assumed mortality rates to incorporate the updated mortality table. As a result of the net impact of changes in these and other assumptions, our fiscal 2018 pension and postretirement medical costs were higher than in the prior year.

Our fiscal 2017 costs were determined using a September 30, 2016 measurement date. At that date, interest and corporate bond rates utilized to determine our discount rates were lower than the interest and corporate bond rates as of September 30, 2015, the measurement date for our fiscal 2016 net periodic cost. Therefore, we decreased the discount rate used to measure our fiscal 2017 net periodic cost from 4.55 percent to 3.73 percent. We maintained the expected return on plan assets of 7.00 percent in the determination of our fiscal 2017 net periodic pension cost based upon expected market returns for our targeted asset allocation. On October 20, 2016, the Society of Actuaries released its annually-updated mortality improvement scale for pension plans incorporating new assumptions surrounding life expectancies in the United States. As of September 30, 2016, we updated our assumed mortality rates to incorporate the updated mortality table. As a result of the net impact of changes in these and other assumptions, our fiscal 2017 pension and postretirement medical costs were consistent with the prior year.

Pension and Postretirement Plan Funding

Generally, our funding policy is to contribute annually an amount that will at least equal the minimum amount required to comply with the Employee Retirement Income Security Act of 1974 (ERISA). However, additional voluntary contributions are made from time to time as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future.

In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2018, 2017 and 2016. Based on these valuations, we have not had a minimum required contribution for the last three fiscal years. However, we made voluntary contributions of $7.0 million, $5.0 million and $15.0 million to our pension plans during fiscal 2018, 2017 and 2016 to achieve a desired PPA funding threshold.

We contributed $17.4 million, $13.7 million and $16.6 million to our postretirement benefits plans for the fiscal years ended September 30, 2018, 2017 and 2016. The contributions represent the portion of the postretirement costs we are responsible for under the terms of our plan and minimum funding required by state regulatory commissions.

Outlook for Fiscal 2019 and Beyond

As of September 30, 2018, interest and corporate bond rates were higher than the rates as of September 30, 2017. Therefore, we increased the discount rate used to measure our fiscal 2019 net periodic cost from 3.89 percent to 4.38 percent. The expected return on plan assets remained consistent with the prior year at 6.75 percent in the determination of our fiscal 2019 net periodic pension cost based upon expected market returns for our targeted asset allocation. On October 23, 2018, the Society of Actuaries released its annually-updated mortality improvement scale for pension plans incorporating new assumptions surrounding life expectancies in the United States. As of September 30, 2018, we updated our assumed mortality rates to incorporate the updated mortality table. As a result of the net impact of changes in these and other assumptions, we expect our fiscal 2019 net periodic pension cost to be lower than fiscal 2018.

Based upon current market conditions, the current funded position of the plans and the funding requirements under the PPA, we do not anticipate a minimum required contribution for fiscal 2019. However, we may consider whether a voluntary contribution is prudent to maintain certain funding levels. The amount of this funding is contingent upon several factors, including the issuance of new mortality tables by the US Treasury Department used to establish plan funding requirements. With respect to our postretirement medical plans, we anticipate contributing between $10 million and $20 million during fiscal 2019.

Actual changes in the fair market value of plan assets and differences between the actual and expected return on plan assets could have a material effect on the amount of pension costs ultimately recognized. A 0.25 percent change in our discount rate would impact our pension and postretirement costs by approximately $2.5 million. A 0.25 percent change in our expected rate of return would impact our pension and postretirement costs by approximately $1.4 million.

The projected liability, future funding requirements and the amount of expense or income recognized for each of our pension and other post-retirement benefit plans are subject to change, depending on the actuarial value of plan assets, and the determination of future benefit obligations as of each subsequent calculation date. These amounts are impacted by actual investment returns, changes in interest rates, changes in the demographic composition of the participants in the plans and other actuarial assumptions.

RECENT ACCOUNTING DEVELOPMENTS

Recent accounting developments and their impact on our financial position, results of operations and cash flows are described in Note 2 to the consolidated financial statements.

ITEM 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

We are exposed to risks associated with commodity prices and interest rates. Commodity price risk is the potential loss that we may incur as a result of changes in the fair value of a particular instrument or commodity. Interest-rate risk is the potential increased cost we could incur when we issue debt instruments or to provide financing and liquidity for our business activities. Additionally, interest-rate risk could affect our ability to issue cost effective equity instruments.

We conduct risk management activities in our distribution and pipeline and storage segments. In our distribution segment, we use a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season. Our risk management activities and related accounting treatment are described in further detail in Note 13 to the consolidated financial statements. Additionally, our earnings are affected by changes in short-term interest rates as a result of our issuance of short-term commercial paper and our other short-term borrowings.

Commodity Price Risk

We purchase natural gas for our distribution operations. Substantially all of the costs of gas purchased for distribution operations are recovered from our customers through purchased gas cost adjustment mechanisms. Therefore, our distribution operations have limited commodity price risk exposure.

Interest Rate Risk

Our earnings are exposed to changes in short-term interest rates associated with our short-term commercial paper program and other short-term borrowings. We use a sensitivity analysis to estimate our short-term interest rate risk. For purposes of this analysis, we estimate our short-term interest rate risk as the difference between our actual interest expense for the period and estimated interest expense for the period assuming a hypothetical average one percent increase in the interest rates associated with our short-term borrowings. Had interest rates associated with our short-term borrowings increased by an average of one percent, our net interest expense would have increased by approximately $0.2 million during 2018.

ITEM 8. ***Financial Statements and Supplementary Data.***

Index to financial statements and financial statement schedule:

All other financial statement schedules are omitted because the required information is not present, or not present in amounts sufficient to require submission of the schedule or because the information required is included in the financial statements and accompanying notes thereto.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Atmos Energy Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Atmos Energy Corporation (the “Company“) as of September 30, 2018 and 2017, the related consolidated statements of income, comprehensive income, shareholders‘ equity, and cash flows, for each of the three years in the period ended September 30, 2018, and the related notes and financial statement schedule listed in the Index at Item 8 (collectively referred to as the "financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of September 30, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2018, in conformity with US generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of September 30, 2018, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated November 13, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company‘s management. Our responsibility is to express an opinion on the Company‘s financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the US federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Company‘s auditor since 1983.
Dallas, Texas
November 13, 2018

ATMOS ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	September 30 2018	September 30 2017
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$ 12,217,648	$ 11,001,910
Construction in progress	349,725	299,394
	12,567,373	11,301,304
Less accumulated depreciation and amortization	2,196,226	2,042,122
Net property, plant and equipment	10,371,147	9,259,182
Current assets		
Cash and cash equivalents	13,771	26,409
Accounts receivable, less allowance for doubtful accounts of $14,795 in 2018 and $10,865 in 2017	253,295	222,263
Gas stored underground	165,732	184,653
Other current assets	46,055	106,321
Total current assets	478,853	539,646
Goodwill	730,419	730,132
Deferred charges and other assets	294,018	220,636
	$ 11,874,437	$ 10,749,596
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: 2018 — 111,273,683 shares, 2017 — 106,104,634 shares	$ 556	$ 531
Additional paid-in capital	2,974,926	2,536,365
Accumulated other comprehensive loss	(83,647)	(105,254)
Retained earnings	1,878,116	1,467,024
Shareholders' equity	4,769,951	3,898,666
Long-term debt	2,493,665	3,067,045
Total capitalization	7,263,616	6,965,711
Commitments and contingencies (See Note 11)		
Current liabilities		
Accounts payable and accrued liabilities	217,283	233,050
Other current liabilities	547,068	332,648
Short-term debt	575,780	447,745
Current maturities of long-term debt	575,000	—
Total current liabilities	1,915,131	1,013,443
Deferred income taxes	1,154,067	1,878,699
Regulatory excess deferred taxes (See Note 12)	739,670	—
Regulatory cost of removal obligation	466,405	485,420
Pension and postretirement liabilities	177,520	230,588
Deferred credits and other liabilities	158,028	175,735
	$ 11,874,437	$ 10,749,596

See accompanying notes to consolidated financial statements.

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended September 30		
	2018	2017	2016
	(In thousands, except per share data)		
Operating revenues			
Distribution segment	$ 3,003,047	$ 2,649,175	$ 2,339,778
Pipeline and storage segment	507,713	457,030	427,196
Intersegment eliminations	(395,214)	(346,470)	(312,326)
Total operating revenues	3,115,546	2,759,735	2,454,648
Purchased gas cost			
Distribution segment	1,559,836	1,269,456	1,058,576
Pipeline and storage segment	1,978	2,506	(58)
Intersegment eliminations	(393,966)	(346,426)	(312,326)
Total purchased gas cost	1,167,848	925,536	746,192
Operation and maintenance expense	599,595	546,798	538,592
Depreciation and amortization expense	361,083	319,448	290,791
Taxes, other than income	263,886	240,407	221,843
Operating income	723,134	727,546	657,230
Miscellaneous expense	(5,344)	(3,270)	(234)
Interest charges	106,646	120,182	114,812
Income from continuing operations before income taxes	611,144	604,094	542,184
Income tax expense	8,080	221,383	196,642
Income from continuing operations	603,064	382,711	345,542
Income from discontinued operations, net of tax ($0, $6,841 and $3,731)	—	10,994	4,562
Gain on sale of discontinued operations, net of tax ($0, $10,215 and $0)	—	2,716	—
Net Income	$ 603,064	$ 396,421	$ 350,104
Basic and diluted net income per share			
Income per share from continuing operations	$ 5.43	$ 3.60	$ 3.33
Income per share from discontinued operations	—	0.13	0.05
Net income per share - basic and diluted	$ 5.43	$ 3.73	$ 3.38
Basic and diluted weighted average shares outstanding	111,012	106,100	103,524

See accompanying notes to consolidated financial statements.

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ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended September 30		
	2018	**2017**	**2016**
		(In thousands)	
Net income	$ 603,064	$ 396,421	$ 350,104
Other comprehensive income (loss), net of tax			
Net unrealized holding gains (losses) on available-for-sale securities, net of tax of $(146), $1,473 and $(245)	(395)	2,564	(465)
Cash flow hedges:			
Amortization and unrealized gain (loss) on interest rate agreements, net of tax of $13,017, $43,238 and $(56,723)	44,936	75,222	(98,682)
Net unrealized gains on commodity cash flow hedges, net of tax of $0, $3,183 and $13,078	—	4,982	20,455
Total other comprehensive income (loss)	44,541	82,768	(78,692)
Total comprehensive income	$ 647,605	$ 479,189	$ 271,412

See accompanying notes to consolidated financial statements.

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common stock					
	Number of Shares	Stated Value	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
	(In thousands, except share and per share data)					
Balance, September 30, 2015	101,478,818	$ 507	$ 2,230,591	$ (109,330)	$ 1,073,029	$ 3,194,797
Net income	—	—	—	—	350,104	350,104
Other comprehensive loss	—	—	—	(78,692)	—	(78,692)
Cash dividends ($1.68 per share)	—	—	—	—	(175,126)	(175,126)
Cumulative effect of accounting change	—	—	—	—	14,527	14,527
Common stock issued:						
Public offering	1,360,756	7	98,567	—	—	98,574
Direct stock purchase plan	133,133	1	9,228	—	—	9,229
Retirement savings plan	359,414	2	25,047	—	—	25,049
1998 Long-term incentive plan	598,439	3	3,175	—	—	3,178
Employee stock-based compensation	—	—	21,419	—	—	21,419
Balance, September 30, 2016	103,930,560	520	2,388,027	(188,022)	1,262,534	3,463,059
Net income	—	—	—	—	396,421	396,421
Other comprehensive income	—	—	—	82,768	—	82,768
Cash dividends ($1.80 per share)	—	—	—	—	(191,931)	(191,931)
Common stock issued:						
Public offering	1,303,494	6	98,749	—	—	98,755
Direct stock purchase plan	112,592	1	8,970	—	—	8,971
Retirement savings plan	228,326	1	17,551	—	—	17,552
1998 Long-term incentive plan	529,662	3	3,698	—	—	3,701
Employee stock-based compensation	—	—	19,370	—	—	19,370
Balance, September 30, 2017	106,104,634	531	2,536,365	(105,254)	1,467,024	3,898,666
Net income	—	—	—	—	603,064	603,064
Other comprehensive income	—	—	—	44,541	—	44,541
Cash dividends ($1.94 per share)	—	—	—	—	(214,906)	(214,906)
Cumulative effect of accounting change (1)	—	—	—	(22,934)	22,934	—
Common stock issued:						
Public offering	4,558,404	22	395,070	—	—	395,092
Direct stock purchase plan	131,213	1	11,322	—	—	11,323
Retirement savings plan	94,081	—	8,240	—	—	8,240
1998 Long-term incentive plan	385,351	2	3,469	—	—	3,471
Employee stock-based compensation	—	—	20,460	—	—	20,460
Balance, September 30, 2018	111,273,683	$ 556	$ 2,974,926	$ (83,647)	$ 1,878,116	$ 4,769,951

(1) See Note 2, "Recent Accounting Pronouncements" for additional information.

See accompanying notes to consolidated financial statements.

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2018	2017	2016
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 603,064	$ 396,421	$ 350,104
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	361,083	319,633	293,096
Deferred income taxes	158,271	227,183	193,556
One-time income tax benefit	(158,782)	—	—
Gain on sale of discontinued operations	—	(12,931)	—
Discontinued cash flow hedging for commodity contracts	—	(10,579)	—
Stock-based compensation	12,863	14,064	14,760
Debt financing costs	7,865	6,469	5,667
Other	5,437	97	1,019
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	(29,208)	(58,696)	(4,847)
(Increase) decrease in gas stored underground	18,921	(35,126)	20,577
(Increase) decrease in other current assets	60,424	9,991	(18,739)
(Increase) decrease in deferred charges and other assets	(10,049)	102,254	(24,860)
Increase (decrease) in accounts payable and accrued liabilities	(11,857)	53,017	(5,195)
Increase (decrease) in other current liabilities	74,707	(78,651)	(44,482)
Increase (decrease) in deferred credits and other liabilities	31,923	(66,056)	14,334
Net cash provided by operating activities	1,124,662	867,090	794,990
CASH FLOWS USED IN INVESTING ACTIVITIES			
Capital expenditures	(1,467,591)	(1,137,089)	(1,086,950)
Acquisition	—	(86,128)	—
Proceeds from the sale of discontinued operations	3,000	140,253	—
Purchases of available-for-sale securities	(46,401)	(53,597)	(32,551)
Proceeds from sale of available-for-sale securities	22,360	31,792	27,019
Maturities of available-for-sale securities	15,716	9,332	6,290
Use tax refund	790	29,790	—
Other, net	8,560	9,341	6,460
Net cash used in investing activities	(1,463,566)	(1,056,306)	(1,079,732)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net increase (decrease) in short-term debt	128,035	(382,066)	371,884
Proceeds from issuance of long-term debt, net of premium/discount	—	884,911	—
Net proceeds from equity offering	395,092	98,755	98,574
Issuance of common stock through stock purchase and employee retirement plans	19,563	26,523	34,278
Settlement of interest rate agreements	—	(36,996)	—
Interest rate agreements cash collateral	—	25,670	(25,670)
Repayment of long-term debt	—	(250,000)	—
Cash dividends paid	(214,906)	(191,931)	(175,126)
Debt issuance costs	—	(6,775)	(317)
Other	(1,518)	—	—
Net cash provided by financing activities	326,266	168,091	303,623
Net increase (decrease) in cash and cash equivalents	(12,638)	(21,125)	18,881
Cash and cash equivalents at beginning of year	26,409	47,534	28,653
Cash and cash equivalents at end of year	$ 13,771	$ 26,409	$ 47,534
CASH PAID (RECEIVED) DURING THE PERIOD FOR:			
Interest	$ 169,987	$ 156,668	$ 154,748
Income taxes	$ 6,102	$ 5,264	$ 7,794

See accompanying notes to consolidated financial statements.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and its subsidiaries are engaged in the regulated natural gas distribution and pipeline and storage businesses. Through our distribution business, we deliver natural gas through sales and transportation arrangements to over three million residential, commercial, public-authority and industrial customers through our six regulated distribution divisions in the service areas described below:

Division	Service Area
Atmos Energy Colorado-Kansas Division	Colorado, Kansas
Atmos Energy Kentucky/Mid-States Division	Kentucky, Tennessee, Virginia(1)
Atmos Energy Louisiana Division	Louisiana
Atmos Energy Mid-Tex Division	Texas, including the Dallas/Fort Worth metropolitan area
Atmos Energy Mississippi Division	Mississippi
Atmos Energy West Texas Division	West Texas

(1) Denotes location where we have more limited service areas.

In addition, we transport natural gas for others through our distribution system. Our distribution business is subject to federal and state regulation and/or regulation by local authorities in each of the states in which our distribution divisions operate. Our corporate headquarters and shared-services function are located in Dallas, Texas, and our customer support centers are located in Amarillo and Waco, Texas.

Our pipeline and storage business, which is also subject to federal and state regulation, consists of the the pipeline and storage operations of our Atmos Pipeline–Texas (APT) Division and our natural gas transmission business in Louisiana. The APT division provides transportation and storage services to our Mid-Tex Division, other third-party local distribution companies, industrial and electric generation customers, as well as marketers and producers. As part of its pipeline operations, APT manages five underground storage facilites in Texas. We also provide ancillary services customary to the pipeline industry including parking arrangements, lending and sales of inventory on hand. Our natural gas transmission operations in Louisiana are comprised of a proprietary 21-mile pipeline located in the New Orleans, Louisiana area that is primarily used to aggregate gas supply for our distribution division in Louisiana under a long-term contract and on a more limited basis, to third parties.

2. Summary of Significant Accounting Policies

Principles of consolidation — The accompanying consolidated financial statements include the accounts of Atmos Energy Corporation and its wholly-owned subsidiaries. All material intercompany transactions have been eliminated; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates' rate regulation process.

Use of estimates — The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The most significant estimates include the allowance for doubtful accounts, unbilled revenues, contingency accruals, pension and postretirement obligations, deferred income taxes, impairment of long-lived assets, risk management and trading activities, fair value measurements and the valuation of goodwill and other long-lived assets. Actual results could differ from those estimates.

Regulation — Our distribution and pipeline and storage operations are subject to regulation with respect to rates, service, maintenance of accounting records and various other matters by the respective regulatory authorities in the states in which we operate. Our accounting policies recognize the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions. Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates. We record certain costs as regulatory assets when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. The amounts to be recovered or recognized are based upon historical experience and our understanding of the regulations. Further, regulation may impact the period in which revenues or expenses are recognized.

Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and a portion of our regulatory liabilities are recorded as a component of other current liabilities and deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities and our regulatory excess deferred taxes and regulatory cost of removal obligation are reported separately. Significant regulatory assets and liabilities as of September 30, 2018 and 2017 included the following:

	September 30	
	2018	2017
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs[(1)]	$ 6,496	$ 26,826
Infrastructure mechanisms[(2)]	96,739	46,437
Deferred gas costs	1,927	65,714
Recoverable loss on reacquired debt	8,702	11,208
Deferred pipeline record collection costs	20,467	11,692
APT annual adjustment mechanism	—	2,160
Rate case costs	2,741	2,629
Other	6,739	10,132
	$ 143,811	$ 176,798
Regulatory liabilities:		
Regulatory excess deferred taxes[(3)]	$ 744,895	$ —
Regulatory cost of service reserve[(4)]	22,508	—
Regulatory cost of removal obligation	522,175	521,330
Deferred gas costs	94,705	15,559
Asset retirement obligation	12,887	12,827
APT annual adjustment mechanism	35,228	—
Pension and postretirement benefit costs	69,113	—
Other	9,486	5,941
	$ 1,510,997	$ 555,657

(1) Includes $6.5 million and $9.4 million of pension and postretirement expense deferred pursuant to regulatory authorization.
(2) Infrastructure mechanisms in Texas and Louisiana allow for the deferral of all eligible expenses associated with capital expenditures incurred pursuant to these rules, including the recording of interest on the deferred expenses until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recovered through base rates.
(3) The TCJA resulted in the remeasurement of the net deferred tax liability included in our rate base. Of this amount, $5.2 million is recorded in other current liabilities. The period and timing of the return of the excess deferred taxes is being determined by regulators in each of our jurisdictions. See Note 12 for further information.
(4) Effective January 1, 2018, regulators in each of our service areas required us to establish a regulatory liability for the difference in recoverable federal taxes included in revenues based on the former 35% federal statutory rate and the new 21% federal statutory rate for service provided on or after January 1, 2018. The period and timing of the return of this liability to utility customers is being determined by regulators in each of our jurisdictions. See Note 12 for further information.

Revenue recognition — Sales of natural gas to our distribution customers are billed on a monthly basis; however, the billing cycle periods for certain classes of customers do not necessarily coincide with accounting periods used for financial reporting purposes. We follow the revenue accrual method of accounting for distribution segment revenues whereby revenues applicable to gas delivered to customers, but not yet billed under the cycle billing method, are estimated and accrued and the related costs are charged to expense.

On occasion, we are permitted to implement new rates that have not been formally approved by our state regulatory commissions, which are subject to refund. As permitted by accounting principles generally accepted in the United States, we recognize this revenue and establish a reserve for amounts that could be refunded based on our experience for the jurisdiction in which the rates were implemented.

Rates established by regulatory authorities are adjusted for increases and decreases in our purchased gas costs through purchased gas cost adjustment mechanisms. Purchased gas cost adjustment mechanisms provide gas distribution companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case to address all of their non-gas costs.

There is no margin generated through purchased gas cost adjustments, but they provide a dollar-for-dollar offset to increases or decreases in our distribution segment's gas costs. The effects of these purchased gas cost adjustment mechanisms are recorded as deferred gas costs on our balance sheet.

Operating revenues for our pipeline and storage segment are recognized in the period in which volumes are transported.

Discontinued operations — Accounting policies specific to our discontinued natural gas marketing business are described in more detail in Note 15.

Cash and cash equivalents — We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Accounts receivable and allowance for doubtful accounts — Accounts receivable arise from natural gas sales to residential, commercial, industrial, municipal and other customers. We establish an allowance for doubtful accounts to reduce the net receivable balance to the amount we reasonably expect to collect based on our collection experience or where we are aware of a specific customer's inability or reluctance to pay. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

Gas stored underground — Our gas stored underground is comprised of natural gas injected into storage to support the winter season withdrawals for our distribution operations. The average cost method is used for all of our distribution operations. Gas in storage that is retained as cushion gas to maintain reservoir pressure is classified as property, plant and equipment and is valued at cost.

Property, plant and equipment — Regulated property, plant and equipment is stated at original cost, net of contributions in aid of construction. The cost of additions includes direct construction costs, payroll related costs (taxes, pensions and other fringe benefits), administrative and general costs and an allowance for funds used during construction. The allowance for funds used during construction represents the estimated cost of funds used to finance the construction of major projects and are capitalized in the rate base for ratemaking purposes when the completed projects are placed in service. Interest expense of $6.8 million, $2.5 million and $2.8 million was capitalized in 2018, 2017 and 2016.

Major renewals, including replacement pipe, and betterments that are recoverable under our regulatory rate base are capitalized while the costs of maintenance and repairs that are not capitalizable are charged to expense as incurred. The costs of large projects are accumulated in construction in progress until the project is completed. When the project is completed, tested and placed in service, the balance is transferred to the regulated plant in service account included in the rate base and depreciation begins.

Regulated property, plant and equipment is depreciated at various rates on a straight-line basis. These rates are approved by our regulatory commissions and are comprised of two components: one based on average service life and one based on cost of removal. Accordingly, we recognize our cost of removal expense as a component of depreciation expense. The related cost of removal accrual is reflected as a regulatory liability on the consolidated balance sheet. At the time property, plant and equipment is retired, removal expenses less salvage, are charged to the regulatory cost of removal accrual. The composite depreciation rate was 3.2 percent, 3.1 percent and 3.2 percent for the fiscal years ended September 30, 2018, 2017 and 2016.

Other property, plant and equipment is stated at cost. Depreciation is generally computed on the straight-line method for financial reporting purposes based upon estimated useful lives.

Asset retirement obligations — We record a liability at fair value for an asset retirement obligation when the legal obligation to retire the asset has been incurred with an offsetting increase to the carrying value of the related asset. Accretion of the asset retirement obligation due to the passage of time is recorded as an operating expense.

As of September 30, 2018 and 2017, we had asset retirement obligations of $12.9 million and $12.8 million. Additionally, we had $7.5 million and $7.8 million of asset retirement costs recorded as a component of property, plant and equipment that will be depreciated over the remaining life of the underlying associated assets.

We believe we have a legal obligation to retire our natural gas storage facilities. However, we have not recognized an asset retirement obligation associated with our storage facilities because we are not able to determine the settlement date of this obligation as we do not anticipate taking our storage facilities out of service permanently. Therefore, we cannot reasonably estimate the fair value of this obligation.

Impairment of long-lived assets — We periodically evaluate whether events or circumstances have occurred that indicate that other long-lived assets may not be recoverable or that the remaining useful life may warrant revision. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, an impairment loss equal to the excess of the asset's carrying value over its fair value is recorded.

Goodwill — We annually evaluate our goodwill balances for impairment during our second fiscal quarter or more frequently as impairment indicators arise. During the second quarter of fiscal 2018, we completed our annual goodwill impairment assessment using a qualitative assessment, as permitted under U.S. GAAP. We test goodwill for impairment at the reporting unit level on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of the reporting unit. Based on the assessment performed, we determined that our goodwill was not impaired. Although not applicable for the fiscal 2018 analysis, if the qualitative assessment resulted in impairment indicators, we would then use a present value technique based on discounted cash flows to estimate the fair value of our reporting units. These calculations are dependent on several subjective factors including the timing of future cash flows, future growth rates and the discount rate. An impairment charge is recognized if the carrying value of a reporting unit's goodwill exceeds its fair value.

Marketable securities — As of September 30, 2018 and 2017, all of our marketable securities were classified as available for sale. In accordance with the current authoritative accounting standards, these securities, including both debt and equity securities, are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on an individual investment by investment basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related investment is written down to its estimated fair value. Beginning on October 1, 2018, changes in fair value of our equity available for sale securities will be recorded in net income as discussed further below in the *Recent accounting pronouncements* section.

Financial instruments and hedging activities — We use financial instruments to mitigate commodity price risk in our distribution and pipeline and storage segments and to mitigate interest rate risk. The objectives and strategies for using financial instruments have been tailored to our continuing business and are discussed in Note 13.

We record all of our financial instruments on the balance sheet at fair value, with changes in fair value ultimately recorded in the income statement. These financial instruments are reported as risk management assets and liabilities and are classified as current or noncurrent other assets or liabilities based upon the anticipated settlement date of the underlying financial instrument. We record the cash flow impact of our financial instruments in operating cash flows based upon their balance sheet classification.

The timing of when changes in fair value of our financial instruments are recorded in the income statement depends on whether the financial instrument has been designated and qualifies as a part of a hedging relationship or if regulatory rulings require a different accounting treatment. Changes in fair value for financial instruments that do not meet one of these criteria are recognized in the income statement as they occur.

Financial Instruments Associated with Commodity Price Risk

In our distribution segment, the costs associated with and the realized gains and losses arising from the use of financial instruments to mitigate commodity price risk are included in our purchased gas cost adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue in accordance with accounting principles generally accepted in the United States. Accordingly, there is no earnings impact on our distribution segment as a result of the use of financial instruments.

Financial Instruments Associated with Interest Rate Risk

We manage interest rate risk, primarily when we plan to issue long-term debt. We currently manage this risk through the use of forward starting interest rate swaps to fix the Treasury yield component of the interest cost associated with anticipated financings. We designate these financial instruments as cash flow hedges at the time the agreements are executed. Unrealized gains and losses associated with the instruments are recorded as a component of accumulated other comprehensive income (loss). When the instruments settle, the realized gain or loss is recorded as a component of accumulated other comprehensive income (loss) and recognized as a component of interest expense over the life of the related financing arrangement. Hedge ineffectiveness to the extent incurred is reported as a component of interest expense. As of September 30, 2018 and September 30, 2017, no cash was required to be held in margin accounts.

Fair Value Measurements — We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We primarily use quoted market prices and other observable market pricing information in valuing our financial assets and liabilities and minimize the use of unobservable pricing inputs in our measurements.

Fair-value estimates also consider our own creditworthiness and the creditworthiness of the counterparties involved. Our counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and the use of collateral requirements under certain circumstances.

Amounts reported at fair value are subject to potentially significant volatility based upon changes in market prices, including, but not limited to, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions and interest rates, each of which directly affect the estimated fair value of our financial instruments. We believe the market prices and models used to value these financial instruments represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then current market conditions.

Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1) and the lowest priority given to unobservable inputs (Level 3). The levels of the hierarchy are described below:

Level 1 — Represents unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is defined as a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Prices actively quoted on national exchanges are used to determine the fair value of most of our assets and liabilities recorded on our balance sheet at fair value.

Our Level 1 measurements consist primarily of our available-for-sale securities. The Level 1 measurements for investments in the Atmos Energy Corporation Master Retirement Trust (the Master Trust), Supplemental Executive Benefit Plan and postretirement benefit plan consist primarily of exchange-traded financial instruments.

Level 2 — Represents pricing inputs other than quoted prices included in Level 1 that are either directly or indirectly observable for the asset or liability as of the reporting date. These inputs are derived principally from, or corroborated by, observable market data. Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps and municipal and corporate bonds where market data for pricing is observable. The Level 2 measurements for investments in our Master Trust, Supplemental Executive Benefit Plan and postretirement benefit plan consist primarily of non-exchange traded financial instruments such as corporate bonds and government securities.

Level 3 — Represents generally unobservable pricing inputs which are developed based on the best information available, including our own internal data, in situations where there is little if any market activity for the asset or liability at the measurement date. The pricing inputs utilized reflect what a market participant would use to determine fair value. We currently do not have any Level 3 investments.

Pension and other postretirement plans — Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. Our measurement date is September 30. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligation and net pension and postretirement cost. When establishing our discount rate, we consider high quality corporate bond rates based on bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds.

The expected long-term rate of return on assets is utilized in calculating the expected return on plan assets component of the annual pension and postretirement plan cost. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors when making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater than or less than the assumed rate, that year's annual pension or postretirement plan cost is not affected. Rather, this gain or loss is amortized over the expected future working lifetime of the plan participants.

The expected return on plan assets is then calculated by applying the expected long-term rate of return on plan assets to the market-related value of the plan assets. The market-related value of our plan assets represents the fair market value of the plan assets, adjusted to smooth out short-term market fluctuations over a five-year period. The use of this calculation will delay the impact of current market fluctuations on the pension expense for the period.

We use a corridor approach to amortize actuarial gains and losses. Under this approach, net gains or losses in excess of ten percent of the larger of the pension benefit obligation or the market-related value of the assets are amortized on a straight-line basis. The period of amortization is the average remaining service of active participants who are expected to receive benefits under the plan.

We estimate the assumed health care cost trend rate used in determining our annual postretirement net cost based upon our actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of retirement is estimated based upon the annual review of our participant census information as of the measurement date.

Income taxes — Income taxes are determined based on the liability method, which results in income tax assets and liabilities arising from temporary differences. Temporary differences are differences between the tax bases of assets and liabilities and their reported amounts in the financial statements that will result in taxable or deductible amounts in future years. The liability method requires the effect of tax rate changes on accumulated deferred income taxes to be reflected in the period in which the rate change was enacted. The liability method also requires that deferred tax assets be reduced by a valuation allowance unless it is more likely than not that the assets will be realized.

The Company may recognize the tax benefit from uncertain tax positions only if it is at least more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon settlement with the taxing authorities. We recognize accrued interest related to unrecognized tax benefits as a component of interest expense. We recognize penalties related to unrecognized tax benefits as a component of miscellaneous income (expense) in accordance with regulatory requirements.

Tax collections — We are allowed to recover from customers revenue-related taxes that are imposed upon us. We record such taxes as operating expenses and record the corresponding customer charges as operating revenues. However, we do collect and remit various other taxes on behalf of various governmental authorities, and we record these amounts in our consolidated balance sheets on a net basis. We do not collect income taxes from our customers on behalf of governmental authorities.

Contingencies — In the normal course of business, we are confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties or the action of various regulatory agencies. For such matters, we record liabilities when they are considered probable and estimable, based on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future. Actual results may differ from estimates, depending on actual outcomes or changes in the facts or expectations surrounding each potential exposure.

Subsequent events — Except as noted in Note 5 and 6 regarding the public offering of senior notes, no events occurred subsequent to the balance sheet date that would require recognition or disclosure in the financial statements.

Recent accounting pronouncements

Accounting pronouncements adopted in fiscal 2018

In February 2018, the Financial Accounting Standards Board (FASB) issued new guidance as a result of the Tax Cuts and Jobs Act of 2017 (the "TCJA"), related to the treatment of certain tax effects from accumulated other comprehensive income. The new guidance allows entities to reclassify from accumulated other comprehensive income to retained earnings the stranded tax effects resulting from the adoption of the TCJA. The new guidance will be effective for us in the fiscal year beginning on October 1, 2019 and for interim periods within that year. Early adoption is permitted, including adoption in any interim period for public business entities for reporting periods for which financial statements have not yet been issued and should be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change in the U.S. federal corporate income tax rate in the Tax Cuts and Jobs Act is recognized. We have early adopted the new standard effective as of September 30, 2018, and reclassified the stranded tax effects of $22.9 million, resulting from the TCJA from accumulated other comprehensive income to retained earnings. This change is reflected on our consolidated statement of shareholders' equity.

In January 2017, the FASB issued new guidance that simplified the accounting for goodwill impairments by eliminating step 2 from the goodwill impairment test. Under the new guidance, if the carrying amount of a reporting unit exceeds its fair value, an impairment loss will be recognized in an amount equal to that excess, limited to the total amount of goodwill allocated to that reporting unit. We early adopted the new standard, effective for our goodwill impairment test performed in our second fiscal quarter of 2018. The new standard did not have a material impact on our results of operations, consolidated balance sheets or cash flows.

Accounting pronouncements that will be effective in fiscal 2019

In May 2014, the FASB issued a comprehensive new revenue recognition standard that superseded virtually all existing revenue recognition guidance under generally accepted accounting principles in the United States. Under the new standard, an entity recognizes revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. In doing so, companies may need to use more judgment and make more estimates than under current guidance. The new guidance will become effective for us October 1, 2018 and can be applied either retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption.

We have completed the evaluation of our sources of revenue and the impact that the new guidance will have on our financial position, results of operations, cash flows and business processes. Based on this evaluation, we do not believe the implementation of the new guidance will have a material effect on our financial position, results of operations, cash flows or business processes. We intend to apply the new guidance using the modified retrospective method on the date of adoption. The most impactful change from the adoption of this standard will be the disclosure requirements. In the first quarter of fiscal 2019, we will add a new revenue footnote which will contain a disaggregation of revenues from contracts with customers by customer type.

In March 2017, the FASB issued new guidance related to the income statement presentation of the components of net periodic benefit cost for an entity's sponsored defined benefit pension and other postretirement plans. The new guidance requires entities to disaggregate the current service cost component of the net benefit cost from the other components and present it with other current compensation costs for related employees in the statement of income. The other components of net benefit cost will be presented outside of income from operations on the statement of income. In addition, only the service cost component of net benefit cost is eligible for capitalization (e.g., as part of inventory or property, plant, and equipment). The Federal Energy Regulatory Commission ("FERC"), which regulates interstate transmission pipelines and also establishes, through its Uniform System of Accounts, accounting practices for rate-regulated entities, has issued guidance that states it will permit an election to either continue to capitalize non-service benefit costs or to cease capitalizing such costs for regulatory purposes. Accounting guidelines by the FERC are typically also followed by state commissions. As such, we plan to continue to capitalize into property, plant and equipment all components of net periodic benefit cost for ratemaking purposes and will defer the non-service cost components as a regulatory asset for U.S. GAAP reporting purposes. The new guidance will be effective for us in the fiscal year beginning on October 1, 2018 and for interim periods within that year. The standard requires retrospective application for presentation of non-service cost components outside of income from operations in the statement of income and prospective application of the change in eligible costs for capitalization. We do not anticipate the new standard will have a material impact on our financial position, results of operations and cash flows.

In January 2016, the FASB issued guidance related to the classification and measurement of financial instruments. The amendments modify the accounting and presentation for certain financial liabilities and equity investments not consolidated or reported using the equity method. The guidance is effective for us beginning October 1, 2018. The standard will require that changes in fair value of our available-for-sale equity securities be recorded in net income. However, the accounting for our available-for-sale debt securities remains unchanged as a result of this guidance. The new guidance will be applied by means of a cumulative-effect adjustment to the balance sheet as of the beginning of fiscal year 2019. We expect to record a cumulative-effect adjustment of approximately $8 million from accumulated other comprehensive income to retained earnings. We do not anticipate the new standard will have a material impact on our financial position, results of operations or cash flows.

In August 2018, the FASB issued new guidance aligning the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software (and hosting arrangements that include an internal-use software license). The amendments require a customer in a hosting arrangement that is a service contract to follow the guidance in Subtopic 350-40 to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. The new guidance is effective for us in the fiscal year beginning October 1, 2020 and for interim periods within that year. Early adoption is permitted, including adoption in any interim period. The amendments should be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. We intend to early adopt the guidance prospectively as of the fiscal year beginning October 1, 2018. We do not anticipate the new standard will have a material impact on our financial position, results of operations or cash flows.

Recently issued accounting pronouncements that will be effective after fiscal 2019

In February 2016, the FASB issued a comprehensive new leasing standard that will require lessees to recognize a lease liability and a right-of-use asset for all leases, including operating leases, with a term greater than 12 months on its balance sheet. The new standard will be effective for us beginning on October 1, 2019; early adoption is permitted. The new leasing standard requires modified retrospective transition, which requires application of the new guidance at the beginning of the earliest comparative period presented in the year of adoption. Additionally, in January 2018, the FASB issued amendments to the standard that provides a practical expedient for entities to not evaluate existing or expired land easements that were not previously accounted for as leases under the current guidance. In July 2018, the FASB issued an amendment to the standard that provides an additional and optional transition method to adopt the standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. We are currently evaluating the effect of this standard and amendments on our financial position, results of operations, cash flows and business processes.

In June 2016, the FASB issued new guidance which will require credit losses on most financial assets measured at amortized cost and certain other instruments to be measured using an expected credit loss model. Under this model, entities will estimate credit losses over the entire contractual term of the instrument from the date of initial recognition of that instrument. In contrast, current U.S. GAAP is based on an incurred loss model that delays recognition of credit losses until it is probable the loss has been incurred. The new guidance also introduces a new impairment recognition model for available-for-sale securities that will require credit losses for available-for-sale debt securities to be recorded through an allowance account. The new standard will be effective for us beginning on October 1, 2021; early adoption is permitted beginning on October 1, 2019. We are currently evaluating the potential impact of this new guidance on our financial position, results of operations and cash flows.

In August 2018, the FASB issued new guidance that modifies the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. The guidance removes the disclosure requirements for the amounts of gain/loss and prior service cost/credit amortization expected in the following year and the disclosure of the effect of a one-percentage-point change in the health care cost trend rate, among other changes. The guidance adds certain disclosures including the weighted average interest crediting rate for cash balance plans and a narrative description for the significant change in gains and losses as well as any other significant change in the plan obligations or assets. The new guidance is effective for us in the fiscal year beginning October 1, 2020 and should be applied on a retrospective basis to all periods presented. Early adoption is permitted. The adoption of this new guidance impacts only our disclosures; however we are still evaluating the timing of our adoption.

3. Segment Information

As of September 30, 2018, we manage and review our consolidated operations through the following three reportable segments:

- The *distribution segment* is primarily comprised of our regulated natural gas distribution and related sales operations in eight states.
- The *pipeline and storage segment* is comprised primarily of the pipeline and storage operations of our Atmos Pipeline-Texas division and our natural gas transmission operations in Louisiana.
- The *natural gas marketing segment* is comprised of our discontinued natural gas marketing business.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our distribution segment operations are geographically dispersed, they are aggregated and reported as a single segment as each natural gas distribution division has similar economic characteristics. In addition, because the pipeline and storage operations of our Atmos Pipeline-Texas division and our natural gas transmission operations in Louisiana have similar economic characteristics, they have been aggregated and reported as a single segment.

The accounting policies of the segments are the same as those described in the summary of significant accounting policies. We evaluate performance based on net income or loss of the respective operating units. We allocate interest and pension expense to the pipeline and storage segment; however, there is no debt or pension liability recorded on the pipeline and storage segment balance sheet. All material intercompany transactions have been eliminated; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates' rate regulation process. Income taxes are allocated to each segment as if each segment's taxes were calculated on a separate return basis.

Income statements and capital expenditures by segment are shown in the following tables.

	Year Ended September 30, 2018			
	Distribution	Pipeline and Storage	Eliminations	Consolidated
	(In thousands)			
Operating revenues from external parties	$ 3,000,404	$ 115,142	$ —	$ 3,115,546
Intersegment revenues	2,643	392,571	(395,214)	—
Total operating revenues	3,003,047	507,713	(395,214)	3,115,546
Purchased gas cost	1,559,836	1,978	(393,966)	1,167,848
Operation and maintenance expense	465,848	134,995	(1,248)	599,595
Depreciation and amortization expense	264,930	96,153	—	361,083
Taxes, other than income	231,566	32,320	—	263,886
Operating income	480,867	242,267	—	723,134
Miscellaneous expense	(1,849)	(3,495)	—	(5,344)
Interest charges	65,850	40,796	—	106,646
Income before income taxes	413,168	197,976	—	611,144
Income tax (benefit) expense	(29,798)	37,878	—	8,080
Net income	$ 442,966	$ 160,098	$ —	$ 603,064
Capital expenditures	$ 1,025,800	$ 441,791	$ —	$ 1,467,591

	Year Ended September 30, 2017				
	Distribution	Pipeline and Storage	Natural Gas Marketing	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$ 2,647,813	$ 111,922	$ —	$ —	$ 2,759,735
Intersegment revenues	1,362	345,108	—	(346,470)	—
Total operating revenues	2,649,175	457,030	—	(346,470)	2,759,735
Purchased gas cost	1,269,456	2,506	—	(346,426)	925,536
Operation and maintenance expense	413,077	133,765	—	(44)	546,798
Depreciation and amortization expense	249,071	70,377	—	—	319,448
Taxes, other than income	211,929	28,478	—	—	240,407
Operating income	505,642	221,904	—	—	727,546
Miscellaneous expense	(1,695)	(1,575)	—	—	(3,270)
Interest charges	79,789	40,393	—	—	120,182
Income from continuing operations before income taxes	424,158	179,936	—	—	604,094
Income tax expense	155,789	65,594	—	—	221,383
Income from continuing operations	268,369	114,342	—	—	382,711
Income from discontinued operations, net of tax	—	—	10,994	—	10,994
Gain on sale of discontinued operations, net of tax	—	—	2,716	—	2,716
Net income	$ 268,369	$ 114,342	$ 13,710	$ —	$ 396,421
Capital expenditures	$ 849,950	$ 287,139	$ —	$ —	$ 1,137,089

	Year Ended September 30, 2016				
	Distribution	Pipeline and Storage	Natural Gas Marketing	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 2,338,404	$ 116,244	$ —	$ —	$ 2,454,648
Intersegment revenues	1,374	310,952	—	(312,326)	—
Total operating revenues	2,339,778	427,196	—	(312,326)	2,454,648
Purchased gas cost	1,058,576	(58)	—	(312,326)	746,192
Operation and maintenance expense	407,982	130,610	—	—	538,592
Depreciation and amortization expense	234,109	56,682	—	—	290,791
Taxes, other than income	197,227	24,616	—	—	221,843
Operating income	441,884	215,346	—	—	657,230
Miscellaneous income (expense)	1,171	(1,405)	—	—	(234)
Interest charges	78,238	36,574	—	—	114,812
Income from continuing operations before income taxes	364,817	177,367	—	—	542,184
Income tax expense	130,987	65,655	—	—	196,642
Income from continuing operations	233,830	111,712	—	—	345,542
Income from discontinued operations, net of tax	—	—	4,562	—	4,562
Net income	$ 233,830	$ 111,712	$ 4,562	$ —	$ 350,104
Capital expenditures	$ 740,246	$ 346,383	$ 321	$ —	$ 1,086,950

The following table summarizes our revenues from external parties by products and services for the fiscal year ended September 30.

	2018	2017	2016
		(In thousands)	
Distribution revenues:			
Gas sales revenues:			
Residential	$ 1,916,101	$ 1,642,918	$ 1,477,049
Commercial	797,073	708,167	619,979
Industrial	131,267	133,372	98,439
Public authority and other	47,714	45,820	41,307
Total gas sales revenues	2,892,155	2,530,277	2,236,774
Transportation revenues	99,250	86,332	76,690
Other gas revenues	8,999	31,204	24,940
Total distribution revenues	3,000,404	2,647,813	2,338,404
Pipeline and storage revenues	115,142	111,922	116,244
Total operating revenues	$ 3,115,546	$ 2,759,735	$ 2,454,648

Balance sheet information at September 30, 2018 and 2017 by segment is presented in the following tables.

	September 30, 2018			
	Distribution	Pipeline and Storage	Eliminations	Consolidated
	(In thousands)			
Property, plant and equipment, net	$ 7,644,693	$ 2,726,454	$ —	$ 10,371,147
Total assets	$ 11,109,128	$ 2,963,480	$ (2,198,171)	$ 11,874,437

	September 30, 2017			
	Distribution	Pipeline and Storage	Eliminations	Consolidated
	(In thousands)			
Property, plant and equipment, net	$ 6,849,517	$ 2,409,665	$ —	$ 9,259,182
Total assets	$ 10,050,164	$ 2,621,601	$ (1,922,169)	$ 10,749,596

4. Earnings Per Share

We use the two-class method of computing earnings per share because we have participating securities in the form of non-vested restricted stock units with a nonforfeitable right to dividend equivalents, for which vesting is predicated solely on the passage of time. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator.

Basic and diluted earnings per share for the fiscal years ended September 30 are calculated as follows:

	2018	2017	2016
	(In thousands, except per share data)		
Basic and Diluted Earnings Per Share from continuing operations			
Income from continuing operations	$ 603,064	$ 382,711	$ 345,542
Less: Income from continuing operations allocated to participating securities	580	475	538
Income from continuing operations available to common shareholders	$ 602,484	$ 382,236	$ 345,004
Basic and diluted weighted average shares outstanding	111,012	106,100	103,524
Income from continuing operations per share — Basic and Diluted	$ 5.43	$ 3.60	$ 3.33
Basic and Diluted Earnings Per Share from discontinued operations			
Income from discontinued operations	$ —	$ 13,710	$ 4,562
Less: Income from discontinued operations allocated to participating securities	—	12	8
Income from discontinued operations available to common shareholders	$ —	$ 13,698	$ 4,554
Basic and diluted weighted average shares outstanding	111,012	106,100	103,524
Income from discontinued operations per share - Basic and Diluted	$ —	$ 0.13	$ 0.05
Net Income per share — Basic and Diluted	$ 5.43	$ 3.73	$ 3.38

5. Debt

Long-term debt

Long-term debt at September 30, 2018 and 2017 consisted of the following:

	2018	2017
	(In thousands)	
Unsecured 8.50% Senior Notes, due March 2019	$ 450,000	$ 450,000
Unsecured 3.00% Senior Notes, due 2027	500,000	500,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Unsecured 5.50% Senior Notes, due 2041	400,000	400,000
Unsecured 4.15% Senior Notes, due 2043	500,000	500,000
Unsecured 4.125% Senior Notes, due 2044	750,000	750,000
Medium term Series A notes, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
Floating-rate term loan, due September 2019(1)	125,000	125,000
Total long-term debt	3,085,000	3,085,000
Less:		
Original issue (premium) / discount on unsecured senior notes and debentures	(4,439)	(4,384)
Debt issuance cost	20,774	22,339
Current maturities	575,000	—
	$ 2,493,665	$ 3,067,045

(1) Up to $200 million can be drawn under this term loan.

Maturities of long-term debt at September 30, 2018 were as follows (in thousands):

2019	$ 575,000
2020	—
2021	—
2022	—
2023	—
Thereafter	2,510,000
	$ 3,085,000

On October 4, 2018, we completed a public offering of $600 million of 4.30% senior notes due 2048. We received net proceeds from the offering, after the underwriting discount and estimated offering expenses, of approximately $591 million, that were used to repay working capital borrowings pursuant to our commercial paper program. The effective interest rate of these notes is 4.37% after giving effect to the offering costs.

On June 8, 2017, we completed a public offering of $500 million of 3.00% senior notes due 2027 and $250 million of 4.125% senior notes due 2044. The effective rate of these notes is 3.12% and 4.40%, after giving effect to the offering costs and the settlement of the associated forward starting interest rate swaps. The net proceeds, excluding the loss on the settlement of the interest rate swaps of $37 million, of approximately $753 million were used to repay our $250 million 6.35% senior unsecured notes at maturity on June 15, 2017 and for general corporate purposes, including the repayment of working capital borrowings pursuant to our commercial paper program.

We utilize short-term debt to provide cost-effective, short-term financing until it can be replaced with a balance of long-term debt and equity financing that achieves the Company’s desired capital structure with an equity-to-capitalization ratio between 50% and 60%, inclusive of long-term and short-term debt. Our short-term borrowing requirements are affected primarily by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers’ needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

Currently, our short-term borrowing requirements are satisfied through a combination of a $1.5 billion commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $1.5 billion of total working capital funding. The primary source of our funding is our commercial paper program, which is supported by a five-year unsecured $1.5 billion credit facility. On March 26, 2018, we executed one of our two one-year extension options which extended the maturity date from September 25, 2021 to September 25, 2022. The facility bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from zero percent to 1.25 percent, based on the Company's credit ratings. Additionally, the facility contains a $250 million accordion feature, which provides the opportunity to increase the total committed loan to $1.75 billion. At September 30, 2018 and 2017, there was $575.8 million and $447.7 million outstanding under our commercial paper program with weighted average interest rates of 2.15% and 1.25%, with weighted average maturities of less than one month.

Additionally, we have a $25 million 364-day unsecured facility, which was renewed on April 1, 2018 and expires March 31, 2019, and a $10 million 364-day unsecured revolving credit facility, which is used primarily to issue letters of credit and which was renewed on September 30, 2018. At September 30, 2018, there were no borrowings outstanding under either of these facilities; however, outstanding letters of credit reduced the total amount available to us under our $10 million unsecured revolving facility to $4.4 million.

The availability of funds under these credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At September 30, 2018, our total-debt-to-total-capitalization ratio, as defined, was 44 percent. In addition, both the interest margin and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

These credit facilities and our public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers. Additionally, our public debt indentures relating to our senior notes and debentures, as well as certain of our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity. We were in compliance with all of our debt covenants as of September 30, 2018. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

6. Shareholders' Equity

Shelf Registration, At-the-Market Equity Sales Program and Equity Issuance

On March 28, 2016, we filed a registration statement with the Securities and Exchange Commission (SEC) that originally permitted us to issue, from time to time, up to $2.5 billion in common stock and/or debt securities, which expires March 28, 2019. At September 30, 2018, approximately $650.0 million of securities remained available for issuance under the shelf registration statement. The issuance of our $600 million senior unsecured notes in October 2018, as discussed in Note 5, effectively exhausted this shelf registration statement.

On November 14, 2017, we filed a prospectus supplement under the registration statement relating to an at-the-market (ATM) equity sales program under which we may issue and sell shares of our common stock up to an aggregate offering price of $500 million, which expires March 28, 2019. During the year ended September 30, 2018, no shares of common stock were sold under our ATM equity sales program.

On November 30, 2017, we filed a prospectus supplement under the registration statement relating to an underwriting agreement to sell 4,558,404 shares of our common stock for $400 million. After expenses, net proceeds from the offering were $395.1 million.

1998 Long-Term Incentive Plan

In August 1998, the Board of Directors approved and adopted the 1998 Long-Term Incentive Plan (LTIP), which became effective in October 1998 after approval by our shareholders. The LTIP is a comprehensive, long-term incentive compensation plan providing for discretionary awards of incentive stock options, non-qualified stock options, stock appreciation rights, bonus stock, time-lapse restricted stock, time-lapse restricted stock units, performance-based restricted stock units and stock units to certain employees and non-employee directors of the Company and our subsidiaries. The objectives of this plan include attracting and retaining the best available personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire our common stock.

Accumulated Other Comprehensive Income (Loss)

We record deferred gains (losses) in accumulated other comprehensive income (AOCI) related to available-for-sale securities, which include equity and debt securities, interest rate agreement cash flow hedges and commodity contract cash flow hedges. Deferred gains (losses) for our available-for-sale securities and commodity contract cash flow hedges are recognized in earnings upon settlement, while deferred gains (losses) related to our interest rate agreement cash flow hedges are recognized in earnings as a component of interest expense, as they are amortized. The following tables provide the components of our accumulated other comprehensive income (loss) balances, net of the related tax effects allocated to each component of other comprehensive income (loss). Additionally, as discussed further in Note 2, we have early adopted a new accounting standard effective as of September 30, 2018. The adoption resulted in a reclassification of the stranded tax effects resulting from the TCJA, from accumulated other comprehensive income to retained earnings, as seen in the table below.

	Available-for-Sale Securities	Interest Rate Agreement Cash Flow Hedges	Total
		(In thousands)	
September 30, 2017	$ 7,048	$ (112,302)	$ (105,254)
Other comprehensive income (loss) before reclassifications	1,426	43,184	44,610
Amounts reclassified from accumulated other comprehensive income	(1,821)	1,752	(69)
Net current-period other comprehensive income (loss)	(395)	44,936	44,541
Cumulative effect of accounting change	1,471	(24,405)	(22,934)
September 30, 2018	$ 8,124	$ (91,771)	$ (83,647)

	Available-for-Sale Securities	Interest Rate Agreement Cash Flow Hedges	Commodity Contracts Cash Flow Hedges	Total
		(In thousands)		
September 30, 2016	$ 4,484	$ (187,524)	$ (4,982)	$ (188,022)
Other comprehensive income (loss) before reclassifications	2,502	74,560	9,847	86,909
Amounts reclassified from accumulated other comprehensive income	62	662	(4,865)	(4,141)
Net current-period other comprehensive income	2,564	75,222	4,982	82,768
September 30, 2017	$ 7,048	$ (112,302)	$ —	$ (105,254)

The following tables detail reclassifications out of AOCI for the fiscal years ended September 30, 2018 and 2017. Amounts in parentheses below indicate decreases to net income in the statement of income.

	Fiscal Year Ended September 30, 2018		
Accumulated Other Comprehensive Income Components	Amount Reclassified from Accumulated Other Comprehensive Income		Affected Line Item in the Statement of Income
	(In thousands)		
Available-for-sale securities[2]	$	2,360	Operation and maintenance expense
		2,360	Total before tax
		(539)	Tax expense
	$	1,821	Net of tax
Cash flow hedges			
Interest rate agreements	$	(2,375)	Interest charges
		(2,375)	Total before tax
		623	Tax benefit
	$	(1,752)	Net of tax
Total reclassifications	$	69	Net of tax

	Fiscal Year Ended September 30, 2017		
Accumulated Other Comprehensive Income Components	Amount Reclassified from Accumulated Other Comprehensive Income		Affected Line Item in the Statement of Income
	(In thousands)		
Available-for-sale securities[2]	$	(97)	Operation and maintenance expense
		(97)	Total before tax
		35	Tax benefit
	$	(62)	Net of tax
Cash flow hedges			
Interest rate agreements	$	(1,043)	Interest charges
Commodity contracts		7,967	Purchased gas cost[1]
		6,924	Total before tax
		(2,721)	Tax expense
	$	4,203	Net of tax
Total reclassifications	$	4,141	Net of tax

(1) Amounts are presented as part of income from discontinued operations on the consolidated statements of income.
(2) Our available-for-sale securities include both debt and equity securities.

7. Retirement and Post-Retirement Employee Benefit Plans

We have both funded and unfunded noncontributory defined benefit plans that together cover most of our employees. We also maintain post-retirement plans that provide health care benefits to retired employees. Finally, we sponsor a defined contribution plan that covers substantially all employees. These plans are discussed in further detail below.

As a rate regulated entity, we generally recover our pension costs in our rates over a period of up to 15 years. The amounts that have not yet been recognized in net periodic pension cost that have been recorded as regulatory assets or liabilities are as follows:

	Defined Benefit Plan	Supplemental Executive Retirement Plans	Postretirement Plans	Total
		(In thousands)		
September 30, 2018				
Unrecognized prior service (credit) cost	$ (1,047)	$ —	$ 1,298	$ 251
Unrecognized actuarial (gain) loss	(2,310)	33,912	(100,966)	(69,364)
	$ (3,357)	$ 33,912	$ (99,668)	$ (69,113)
September 30, 2017				
Unrecognized prior service (credit) cost	$ (1,278)	$ —	$ 1,309	$ 31
Unrecognized actuarial (gain) loss	62,388	42,170	(87,196)	17,362
	$ 61,110	$ 42,170	$ (85,887)	$ 17,393

Defined Benefit Plans

Employee Pension Plan

As of September 30, 2018, we maintained one defined benefit plan, the Atmos Energy Corporation Pension Account Plan (the Plan). The assets of the Plan are held within the Atmos Energy Corporation Master Retirement Trust (the Master Trust). The Plan is a cash balance pension plan that was established effective January 1999 and covers most of the employees of Atmos Energy that were hired on or before September 30, 2010. The plan was closed to new participants effective October 1, 2010.

Opening account balances were established for participants as of January 1999 equal to the present value of their respective accrued benefits under the pension plans which were previously in effect as of December 31, 1998. The Plan credits an allocation to each participant's account at the end of each year according to a formula based on the participant's age, service and total pay (excluding incentive pay). In addition, at the end of each year, a participant's account is credited with interest on the employee's prior year account balance. Participants are fully vested in their account balances after three years of service and may choose to receive their account balances as a lump sum or an annuity.

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974, including the funding requirements under the Pension Protection Act of 2006 (PPA). However, additional voluntary contributions are made from time to time as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future.

During fiscal 2018 and 2017 we contributed $7.0 million and $5.0 million in cash to the Plan to achieve a desired level of funding while maximizing the tax deductibility of this payment. Based upon market conditions at September 30, 2018, the current funded position of the Plan and the funding requirements under the PPA, we do not anticipate a minimum required contribution for fiscal 2019. However, we may consider whether a voluntary contribution is prudent to maintain certain funding levels.

We make investment decisions and evaluate performance of the assets in the Master Trust on a medium-term horizon of at least three to five years. We also consider our current financial status when making recommendations and decisions regarding the Master Trust's assets. Finally, we strive to ensure the Master Trust's assets are appropriately invested to maintain an acceptable level of risk and meet the Master Trust's long-term asset investment policy adopted by the Board of Directors.

To achieve these objectives, we invest the Master Trust's assets in equity securities, fixed income securities, interests in commingled pension trust funds, other investment assets and cash and cash equivalents. Investments in equity securities are diversified among the market's various subsectors in an effort to diversify risk and maximize returns. Fixed income securities are invested in investment grade securities. Cash equivalents are invested in securities that either are short term (less than 180 days) or readily convertible to cash with modest risk.

The following table presents asset allocation information for the Master Trust as of September 30, 2018 and 2017.

Security Class	Targeted Allocation Range	Actual Allocation September 30 2018	Actual Allocation September 30 2017
Domestic equities	35%-55%	44.3%	43.9%
International equities	10%-20%	15.4%	17.2%
Fixed income	5%-30%	16.9%	10.6%
Company stock	0%-15%	12.7%	11.8%
Other assets	0%-20%	10.7%	16.5%

At September 30, 2018 and 2017, the Plan held 716,700 shares of our common stock which represented 12.7 percent and 11.8 percent of total Plan assets. These shares generated dividend income for the Plan of approximately $1.4 million and $1.7 million during fiscal 2018 and 2017.

Our employee pension plan expenses and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets and assumed discount rates and demographic data. We review the estimates and assumptions underlying our employee pension plans annually based upon a September 30 measurement date. The development of our assumptions is fully described in our significant accounting policies in Note 2. The actuarial assumptions used to determine the pension liability for the Plan was determined as of September 30, 2018 and 2017 and the actuarial assumptions used to determine the net periodic pension cost for the Plan was determined as of September 30, 2017, 2016 and 2015. On October 23, 2018, the Society of Actuaries released its annually-updated mortality improvement scale for pension plans incorporating new assumptions surrounding life expectancies in the United States. As of September 30, 2018, we updated our assumed mortality rates to incorporate the updated mortality table.

Additional assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2018	2017	2018	2017	2016
Discount rate	4.38%	3.89%	3.89%	3.73%	4.55%
Rate of compensation increase	3.50%	3.50%	3.50%	3.50%	3.50%
Expected return on plan assets	6.75%	6.75%	6.75%	7.00%	7.00%

The following table presents the Plan's accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2018 and 2017:

	2018	2017
	(In thousands)	
Accumulated benefit obligation	$ 478,750	$ 505,355
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 533,455	$ 545,480
Service cost	17,264	18,109
Interest cost	20,803	20,443
Actuarial (gain) loss	(29,087)	(16,347)
Benefits paid	(37,716)	(34,230)
Benefit obligation at end of year	504,719	533,455
Change in plan assets:		
Fair value of plan assets at beginning of year	508,244	473,950
Actual return on plan assets	54,163	63,524
Employer contributions	7,000	5,000
Benefits paid	(37,716)	(34,230)
Fair value of plan assets at end of year	531,691	508,244
Reconciliation:		
Funded status	26,972	(25,211)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Net amount recognized	$ 26,972	$ (25,211)

Net periodic pension cost for the Plan for fiscal 2018, 2017 and 2016 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2018	2017	2016
		(In thousands)	
Components of net periodic pension cost:			
Service cost	$ 17,264	$ 18,109	$ 16,419
Interest cost	20,803	20,443	23,193
Expected return on assets	(27,666)	(27,975)	(27,522)
Amortization of prior service credit	(231)	(231)	(226)
Recognized actuarial loss	9,114	12,744	10,693
Net periodic pension cost	$ 19,284	$ 23,090	$ 22,557

The following table sets forth by level, within the fair value hierarchy, the Plan's assets at fair value as of September 30, 2018 and 2017. As required by authoritative accounting literature, assets are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement. The methods used to determine fair value for the assets held by the Plan are fully described in Note 2. Investments in our common/collective trusts and limited partnerships that are measured at net asset value per share equivalent are not classified in the fair value hierarchy. The net asset value amounts presented are intended to reconcile the fair value hierarchy to the total investments. In addition to the assets shown below, the Plan had net accounts receivable of $2.0 million and $0.6 million at September 30, 2018 and 2017, which materially approximates fair value due to the short-term nature of these assets.

	Assets at Fair Value as of September 30, 2018			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Investments:				
Common stocks	$ 197,577	$ —	$ —	$ 197,577
Money market funds	—	19,153	—	19,153
Registered investment companies	50,895	—	—	50,895
Government securities:				
Mortgage-backed securities	—	18,821	—	18,821
U.S. treasuries	23,071	868	—	23,939
Corporate bonds	—	46,498	—	46,498
Total investments at fair value	$ 271,543	$ 85,340	$ —	356,883
Investments measured at net asset value:				
Common/collective trusts [(1)]				108,391
Limited partnerships [(1)]				64,399
Total investments at fair value				$ 529,673

	Assets at Fair Value as of September 30, 2017			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Investments:				
Common stocks	$ 164,910	$ —	$ —	$ 164,910
Money market funds	—	9,588	—	9,588
Registered investment companies	64,102	—	—	64,102
Government securities:				
Mortgage-backed securities	—	15,664	—	15,664
U.S. treasuries	5,129	822	—	5,951
Corporate bonds	—	32,314	—	32,314
Total assets in the fair value hierarchy	$ 234,141	$ 58,388	$ —	292,529
Investments measured at net asset value:				
Common/collective trusts [(1)]				150,976
Limited partnerships [(1)]				64,135
Total investments at fair value				$ 507,640

(1) The fair value of our common/collective trusts and limited partnerships are measured using the net asset value per share practical expedient. There are no redemption restrictions, redemption notice periods or unfunded commitments for these investments. The redemption frequency is daily.

Supplemental Executive Retirement Plans

We have three nonqualified supplemental plans which provide additional pension, disability and death benefits to our officers, division presidents and certain other employees of the Company.

The first plan is referred to as the Supplemental Executive Benefits Plan (SEBP) and covers our officers, division presidents and certain other employees of the Company who were employed on or before August 12, 1998. The SEBP is a defined benefit arrangement which provides a benefit equal to 75 percent of covered compensation under which benefits paid from the underlying qualified defined benefit plan are an offset to the benefits under the SEBP.

In August 1998, we adopted the Supplemental Executive Retirement Plan (SERP) (formerly known as the Performance-Based Supplemental Executive Benefits Plan), which covers all officers or division presidents selected to participate in the plan between August 12, 1998 and August 5, 2009 and any corporate officer who was appointed to the Management Committee through December 31, 2016. The SERP is a defined benefit arrangement which provides a benefit equal to 60 percent of covered compensation under which benefits paid from the underlying qualified defined benefit plan are an offset to the benefits under the SERP.

Effective August 5, 2009, we adopted a new defined benefit Supplemental Executive Retirement Plan (the 2009 SERP), for corporate officers, division presidents or any other employees selected at the discretion of the Board. Under the 2009 SERP, a nominal account has been established for each participant, to which the Company contributes at the end of each calendar year an amount equal to ten percent (25 percent for members of the Management Committee appointed on or after January 1, 2017) of the total of each participant's base salary and cash incentive compensation earned during each prior calendar year, beginning December 31, 2009. The benefits vest after three years of service and attainment of age 55 and earn interest credits at the same annual rate as the Company's Pension Account Plan (currently 4.69%).

Due to the retirement of certain executives, during fiscal 2018 we recognized a one-time settlement charge of $4.2 million associated with our SERP and paid $13.9 million in lump sums in relation to the retirements.

Similar to our employee pension plans, we review the estimates and assumptions underlying our supplemental plans annually based upon a September 30 measurement date using the same techniques as our employee pension plans. The actuarial assumptions used to determine the pension liability for the supplemental plans were determined as of September 30, 2018 and 2017 and the actuarial assumptions used to determine the net periodic pension cost for the supplemental plans were determined as of September 30, 2017, 2016 and 2015. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2018	2017	2018	2017	2016
Discount rate[1]	4.38%	3.89%	4.08%	3.73%	4.55%
Rate of compensation increase	3.50%	3.50%	3.50%	3.50%	3.50%

(1) Reflects a weighted average discount rate for pension cost for fiscal 2018 due to settlements during the year.

The following table presents the supplemental plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2018 and 2017:

	2018	2017
	(In thousands)	
Accumulated benefit obligation	$ 116,943	$ 130,070
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 134,480	$ 142,574
Service cost	1,332	2,756
Interest cost	4,988	4,744
Actuarial (gain) loss	(1,020)	(2,452)
Benefits paid	(4,523)	(4,588)
Settlements	(13,887)	(8,554)
Benefit obligation at end of year	121,370	134,480
Change in plan assets:		
Fair value of plan assets at beginning of year	—	—
Employer contribution	18,410	13,142
Benefits paid	(4,523)	(4,588)
Settlements	(13,887)	(8,554)
Fair value of plan assets at end of year	—	—
Reconciliation:		
Funded status	(121,370)	(134,480)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued pension cost	$ (121,370)	$ (134,480)

Assets for the supplemental plans are held in separate rabbi trusts. At September 30, 2018 and 2017, assets held in the rabbi trusts consisted of available-for-sale securities of $46.5 million and $42.9 million, which are included in our fair value disclosures in Note 14.

Net periodic pension cost for the supplemental plans for fiscal 2018, 2017 and 2016 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2018	2017	2016
		(In thousands)	
Components of net periodic pension cost:			
Service cost	$ 1,332	$ 2,756	$ 2,371
Interest cost	4,988	4,744	5,185
Recognized actuarial loss	3,079	4,251	2,586
Settlements	4,159	2,685	—
Net periodic pension cost	$ 13,558	$ 14,436	$ 10,142

Estimated Future Benefit Payments

The following benefit payments for our defined benefit plans, which reflect expected future service, as appropriate, are expected to be paid in the following fiscal years:

	Pension Plan	Supplemental Plans
	(In thousands)	
2019	$ 32,603	$ 10,475
2020	33,509	24,778
2021	35,838	4,597
2022	37,176	20,882
2023	38,684	12,735
2024-2028	206,563	43,070

Postretirement Benefits

We sponsor the Retiree Medical Plan for Retirees and Disabled Employees of Atmos Energy Corporation (the Atmos Retiree Medical Plan). This plan provides medical and prescription drug protection to all qualified participants based on their date of retirement. The Atmos Retiree Medical Plan provides different levels of benefits depending on the level of coverage chosen by the participants and the terms of predecessor plans; however, we generally pay 80 percent of the projected net claims and administrative costs and participants pay the remaining 20 percent. Effective January 1, 2015, for employees who had not met the participation requirements by September 30, 2009, the contribution rates for the Company are limited to a three percent cost increase in claims and administrative costs each year, with the participant responsible for the additional costs.

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of ERISA. However, additional voluntary contributions are made annually as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future. We expect to contribute between $10 million and $20 million to our postretirement benefits plan during fiscal 2019.

We maintain a formal investment policy with respect to the assets in our postretirement benefits plan to ensure the assets funding the postretirement benefit plan are appropriately invested to maintain an acceptable level of risk. We also consider our current financial status when making recommendations and decisions regarding the postretirement benefits plan.

We currently invest the assets funding our postretirement benefit plan in diversified investment funds which consist of common stocks, preferred stocks and fixed income securities. The diversified investment funds may invest up to 75 percent of assets in common stocks and convertible securities. The following table presents asset allocation information for the postretirement benefit plan assets as of September 30, 2018 and 2017.

	Actual Allocation September 30	
Security Class	2018	2017
Diversified investment funds	97.5%	97.5%
Cash and cash equivalents	2.5%	2.5%

Similar to our employee pension and supplemental plans, we review the estimates and assumptions underlying our postretirement benefit plan annually based upon a September 30 measurement date using the same techniques as our employee pension plans. The actuarial assumptions used to determine the pension liability for our postretirement plan were determined as of September 30, 2018 and 2017 and the actuarial assumptions used to determine the net periodic pension cost for the postretirement plan were determined as of September 30, 2017, 2016 and 2015. The assumptions are presented in the following table:

	Postretirement Liability		Postretirement Cost		
	2018	2017	2018	2017	2016
Discount rate	4.38%	3.89%	3.89%	3.73%	4.55%
Expected return on plan assets	5.33%	4.29%	4.29%	4.45%	4.45%
Initial trend rate	6.50%	7.00%	7.00%	7.50%	7.50%
Ultimate trend rate	5.00%	5.00%	5.00%	5.00%	5.00%
Ultimate trend reached in	2022	2022	2022	2022	2021

The following table presents the postretirement plan's benefit obligation and funded status as of September 30, 2018 and 2017:

	2018	2017
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 274,098	$ 279,222
Service cost	12,078	12,436
Interest cost	10,907	10,679
Plan participants' contributions	4,720	4,936
Actuarial gain	(17,252)	(21,750)
Benefits paid	(18,565)	(13,970)
Plan amendments	—	2,545
Benefit obligation at end of year	265,986	274,098
Change in plan assets:		
Fair value of plan assets at beginning of year	184,790	158,977
Actual return on plan assets	10,997	21,160
Employer contributions	17,419	13,687
Plan participants' contributions	4,720	4,936
Benefits paid	(18,565)	(13,970)
Fair value of plan assets at end of year	199,361	184,790
Reconciliation:		
Funded status	(66,625)	(89,308)
Unrecognized transition obligation	—	—
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued postretirement cost	$ (66,625)	$ (89,308)

Net periodic postretirement cost for fiscal 2018, 2017 and 2016 is recorded as operating expense and included the components presented below.

	Fiscal Year Ended September 30		
	2018	2017	2016
		(In thousands)	
Components of net periodic postretirement cost:			
Service cost	$ 12,078	$ 12,436	$ 10,823
Interest cost	10,907	10,679	12,424
Expected return on assets	(8,006)	(7,185)	(6,264)
Amortization of transition obligation	—	—	82
Amortization of prior service cost (credit)	11	(1,644)	(1,644)
Recognized actuarial gain	(6,473)	(2,827)	(2,167)
Net periodic postretirement cost	$ 8,517	$ 11,459	$ 13,254

Assumed health care cost trend rates have a significant effect on the amounts reported for the plan. A one-percentage point change in assumed health care cost trend rates would have the following effects on the latest actuarial calculations:

	One-Percentage Point Increase	One-Percentage Point Decrease
	(In thousands)	
Effect on total service and interest cost components	$ 4,228	$ (3,377)
Effect on postretirement benefit obligation	$ 38,633	$ (31,872)

We are currently recovering other postretirement benefits costs through our regulated rates in substantially all of our service areas under accrual accounting as prescribed by accounting principles generally accepted in the United States. Other postretirement benefits costs have been specifically addressed in rate orders in each jurisdiction served by our Kentucky/Mid-States, West Texas, Mid-Tex and Mississippi Divisions as well as our Kansas jurisdiction and Atmos Pipeline – Texas or have been included in a rate case and not disallowed. Management believes that this accounting method is appropriate and will continue to seek rate recovery of accrual-based expenses in its ratemaking jurisdictions that have not yet approved the recovery of these expenses.

The following tables set forth by level, within the fair value hierarchy, the Retiree Medical Plan's assets at fair value as of September 30, 2018 and 2017. The methods used to determine fair value for the assets held by the Retiree Medical Plan are fully described in Note 2.

	Assets at Fair Value as of September 30, 2018			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Investments:				
Money market funds	$ —	$ 5,003	$ —	$ 5,003
Registered investment companies	194,358	—	—	194,358
Total investments at fair value	$ 194,358	$ 5,003	$ —	$ 199,361

	Assets at Fair Value as of September 30, 2017			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Investments:				
Money market funds	$ —	$ 4,534	$ —	$ 4,534
Registered investment companies	180,256	—	—	180,256
Total investments at fair value	$ 180,256	$ 4,534	$ —	$ 184,790

Estimated Future Benefit Payments

The following benefit payments paid by us, retirees and prescription drug subsidy payments for our postretirement benefit plans, which reflect expected future service, as appropriate, are expected to be paid in the following fiscal years. Company payments for fiscal 2018 include contributions to our postretirement plan trusts.

	Company Payments	Retiree Payments	Subsidy Payments	Total Postretirement Benefits
	(In thousands)			
2019	$ 14,407	$ 3,532	$ —	$ 17,939
2020	13,363	3,742	—	17,105
2021	13,572	3,975	—	17,547
2022	14,503	4,412	—	18,915
2023	15,405	4,832	—	20,237
2024-2028	88,120	29,514	—	117,634

Defined Contribution Plan

The Atmos Energy Corporation Retirement Savings Plan and Trust (the Retirement Savings Plan) covers substantially all employees and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Effective January 1, 2007, employees automatically become participants of the Retirement Savings Plan on the date of employment. Participants may elect a salary reduction up to a maximum of 65 percent of eligible compensation, as defined by the Plan, not to exceed the maximum allowed by the Internal Revenue Service. New participants are automatically enrolled in the Plan at a contribution rate of four percent of eligible compensation, from which they may opt out. We match 100 percent of a participant's contributions, limited to four percent of the participant's salary. Participants are eligible to receive matching contributions after completing one year of service, in which they are immediately vested. Participants are also permitted to take out a loan against their accounts subject to certain restrictions. Employees hired on or after October 1, 2010 participate in the enhanced plan in which participants receive a fixed annual contribution of four percent of eligible earnings to their Retirement Savings Plan account. Participants will continue to be eligible for company matching contributions of up to four percent of their eligible earnings and will be fully vested in the fixed annual contribution after three years of service.

Matching and fixed annual contributions to the Retirement Savings Plan are expensed as incurred and amounted to $16.2 million, $15.4 million and $15.8 million for fiscal years 2018, 2017 and 2016. At September 30, 2018 and 2017, the Retirement Savings Plan held 3.2 percent and 3.7 percent of our outstanding common stock.

8. Stock and Other Compensation Plans

Stock-Based Compensation Plans

Total stock-based compensation cost was $23.9 million, $23.1 million and $24.6 million for the fiscal years ended September 30, 2018, 2017 and 2016. Of this amount, $11.1 million, $9.0 million and $9.8 million was capitalized. Tax benefits related to stock-based compensation were $2.3 million, $4.4 million and $5.0 million for the fiscal years ended September 30, 2018, 2017 and 2016.

1998 Long-Term Incentive Plan

We have a Long-Term Incentive Plan (LTIP), which provides a long-term incentive compensation plan providing for discretionary awards of incentive stock options, non-qualified stock options, stock appreciation rights, bonus stock, time-lapse restricted stock, time-lapse restricted stock units, performance-based restricted stock units and stock units to certain employees and non-employee directors of the Company and our subsidiaries. The objectives of this plan include attracting and retaining the best available personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire common stock.

As of September 30, 2018, we were authorized to grant awards for up to a maximum cumulative amount of 11.2 million shares of common stock under this plan subject to certain adjustment provisions. As of September 30, 2018, non-qualified stock options, bonus stock, time-lapse restricted stock, time-lapse restricted stock units, performance-based restricted stock units and stock units had been issued under this plan, and 1.8 million shares are available for future issuance through September 30, 2021.

Restricted Stock Units Award Grants

As noted above, the LTIP provides for discretionary awards of restricted stock units to help attract, retain and reward employees of Atmos Energy and its subsidiaries. Certain of these awards vest based upon the passage of time and other awards vest based upon the passage of time and the achievement of specified performance targets. The fair value of the awards granted is based on the market price of our stock at the date of grant. We estimate forfeitures using our historical forfeiture rate. The associated expense is recognized ratably over the vesting period. We use authorized and unissued shares to meet share requirements for the vesting of restricted stock units.

Employees who are granted time-lapse restricted stock units under our LTIP have a nonforfeitable right to dividend equivalents that are paid at the same rate and at the same time at which they are paid on shares of stock without restrictions. Time-lapse restricted stock units contain only a service condition that the employee recipients render continuous services to the Company for a period of three years from the date of grant, except for accelerated vesting in the event of death, disability, change of control of the Company or termination without cause (with certain exceptions). There are no performance conditions required to be met for employees to be vested in time-lapse restricted stock units.

Employees who are granted performance-based restricted stock units under our LTIP have a forfeitable right to dividend equivalents that accrue at the same rate at which they are paid on shares of stock without restrictions. Dividend equivalents on the performance-based restricted stock units are paid either in cash or in the form of shares upon the vesting of the award.

Performance-based restricted stock units contain a service condition that the employee recipients render continuous services to the Company for a period of three years from the beginning of the applicable three-year performance period, except for accelerated vesting in the event of death, disability, change of control of the Company or termination without cause (with certain exceptions) and a performance condition based on a cumulative earnings per share target amount.

The following summarizes information regarding the restricted stock units granted under the plan during the fiscal years ended September 30, 2018, 2017 and 2016:

	2018		2017		2016	
	Number of Restricted Units	Weighted Average Grant-Date Fair Value	Number of Restricted Units	Weighted Average Grant-Date Fair Value	Number of Restricted Units	Weighted Average Grant-Date Fair Value
Nonvested at beginning of year	570,814	$ 69.45	782,431	$ 57.66	878,104	$ 48.24
Granted	248,710	85.62	273,497	74.15	357,323	65.98
Vested	(274,392)	64.43	(448,326)	52.23	(448,136)	45.88
Forfeited	(6,540)	74.87	(36,788)	63.48	(4,860)	53.52
Nonvested at end of year	538,592	$ 80.91	570,814	$ 69.45	782,431	$ 57.66

As of September 30, 2018, there was $11.5 million of total unrecognized compensation cost related to nonvested restricted stock units granted under the LTIP. That cost is expected to be recognized over a weighted average period of 1.6 years. The fair value of restricted stock vested during the fiscal years ended September 30, 2018, 2017 and 2016 was $17.2 million, $23.4 million and $20.6 million.

Other Plans

Direct Stock Purchase Plan

We maintain a Direct Stock Purchase Plan, open to all investors, which allows participants to have all or part of their cash dividends paid quarterly in additional shares of our common stock. The minimum initial investment required to join the plan is $1,250. Direct Stock Purchase Plan participants may purchase additional shares of our common stock as often as weekly with voluntary cash payments of at least $25, up to an annual maximum of $100,000.

Equity Incentive and Deferred Compensation Plan for Non-Employee Directors

We have an Equity Incentive and Deferred Compensation Plan for Non–Employee Directors, which provides non-employee directors of Atmos Energy with the opportunity to defer receipt, until retirement, of compensation for services rendered to the Company and invest deferred compensation into either a cash account or a stock account.

Other Discretionary Compensation Plans

We have an annual incentive program covering substantially all employees to give each employee an opportunity to share in our financial success based on the achievement of key performance measures considered critical to achieving business objectives for a given year with minimum and maximum thresholds. The Company must meet the minimum threshold for the plan to be funded and distributed to employees. These performance measures may include earnings growth objectives, improved cash flow objectives or crucial customer satisfaction and safety results. We monitor progress towards the achievement of the performance measures throughout the year and record accruals based upon the expected payout using the best estimates available at the time the accrual is recorded. During the last several fiscal years, we have used earnings per share as our sole performance measure.

9. Details of Selected Consolidated Balance Sheet Captions

The following tables provide additional information regarding the composition of certain of our balance sheet captions.

Accounts receivable

Accounts receivable was comprised of the following at September 30, 2018 and 2017:

	September 30	
	2018	2017
	(In thousands)	
Billed accounts receivable	$ 138,794	$ 135,091
Unbilled revenue	81,005	73,143
Other accounts receivable	48,291	24,894
Total accounts receivable	268,090	233,128
Less: allowance for doubtful accounts	(14,795)	(10,865)
Net accounts receivable	$ 253,295	$ 222,263

Other current assets

Other current assets as of September 30, 2018 and 2017 were comprised of the following accounts.

	September 30	
	2018	2017
	(In thousands)	
Deferred gas costs	$ 1,927	$ 65,714
Prepaid expenses	33,233	32,163
Materials and supplies	8,106	4,472
Assets from risk management activities	1,369	2,436
Other	1,420	1,536
Total	$ 46,055	$ 106,321

Property, plant and equipment

Property, plant and equipment was comprised of the following as of September 30, 2018 and 2017:

	September 30	
	2018	2017
	(In thousands)	
Storage plant	$ 414,857	$ 369,510
Transmission plant	2,851,423	2,521,671
Distribution plant	8,141,733	7,306,021
General plant	771,355	765,728
Intangible plant	38,280	38,980
	12,217,648	11,001,910
Construction in progress	349,725	299,394
	12,567,373	11,301,304
Less: accumulated depreciation and amortization	(2,196,226)	(2,042,122)
Net property, plant and equipment(1)	$ 10,371,147	$ 9,259,182

(1) Net property, plant and equipment includes plant acquisition adjustments of $(55.5) million and $(64.1) million at September 30, 2018 and 2017.

Goodwill

The following presents our goodwill balance allocated by segment and changes in the balance for the fiscal year ended September 30, 2018:

	Distribution	Pipeline and Storage	Total
		(In thousands)	
Balance as of September 30, 2017	$ 587,080	$ 143,052	$ 730,132
Deferred tax adjustments on prior acquisitions(1)	262	25	287
Balance as of September 30, 2018	$ 587,342	$ 143,077	$ 730,419

(1) We annually adjust certain deferred taxes recorded in connection with acquisitions completed in fiscal 2001 and fiscal 2005, which resulted in an increase to goodwill and net deferred tax liabilities of $0.3 million for fiscal 2018.

Deferred charges and other assets

Deferred charges and other assets as of September 30, 2018 and 2017 were comprised of the following accounts.

	September 30	
	2018	2017
	(In thousands)	
Marketable securities	$ 99,385	$ 88,409
Regulatory assets	141,778	110,977
Assets from risk management activities	250	803
Pension asset	26,972	—
Tax receivable	10,099	—
Other	15,534	20,447
Total	$ 294,018	$ 220,636

Accounts payable and accrued liabilities

Accounts payable and accrued liabilities as of September 30, 2018 and 2017 were comprised of the following accounts.

	September 30	
	2018	2017
	(In thousands)	
Trade accounts payable	$ 135,159	$ 143,422
Accrued gas payable	48,721	50,253
Accrued liabilities	33,403	39,375
Total	$ 217,283	$ 233,050

Other current liabilities

Other current liabilities as of September 30, 2018 and 2017 were comprised of the following accounts.

	September 30	
	2018	2017
	(In thousands)	
Customer credit balances and deposits	$ 52,648	$ 54,627
Accrued employee costs	52,101	46,653
Deferred gas costs	94,705	15,559
Accrued interest	39,486	39,624
Liabilities from risk management activities	56,734	322
Taxes payable	123,457	116,291
Pension and postretirement obligations	10,475	18,411
Regulatory cost of service reserve	22,508	—
Regulatory cost of removal obligation	55,770	35,910
APT annual adjustment mechanism	19,918	—
Regulatory excess deferred taxes (See Note 12)	5,225	—
Other	14,041	5,251
Total	$ 547,068	$ 332,648

Deferred credits and other liabilities

Deferred credits and other liabilities as of September 30, 2018 and 2017 were comprised of the following accounts.

	September 30	
	2018	2017
	(In thousands)	
Customer advances for construction	$ 11,010	$ 9,309
Other regulatory liabilities	78,599	5,257
Asset retirement obligation	12,887	12,827
Liabilities from risk management activities	103	112,076
APT annual adjustment mechanism	15,310	—
Other	40,119	36,266
Total	$ 158,028	$ 175,735

10. Leases

We have entered into operating leases for towers, office and warehouse space, vehicles and heavy equipment used in our operations. The remaining lease terms range from one to 13 years and generally provide for the payment of taxes, insurance and maintenance by the lessee. Renewal options exist for certain of these leases.

The related future minimum lease payments at September 30, 2018 were as follows:

	Operating Leases(1)
	(In thousands)
2019	$ 17,655
2020	16,483
2021	16,202
2022	16,004
2023	15,621
Thereafter	22,226
Total minimum lease payments	$ 104,191

(1) Future minimum lease payments do not include amounts for fleet leases and other de minimis items that can be renewed beyond the initial lease term. The Company anticipates renewing the leases beyond the initial term, but the anticipated payments associated with the renewals do not meet the definition of expected minimum lease payments and therefore are not included above. Expected payments are $17.7 million in 2019, $14.7 million in 2020, $11.3 million in 2021, $8.0 million in 2022, $4.6 million in 2023 and $2.3 million thereafter.

Consolidated lease and rental expense amounted to $33.8 million, $32.7 million and $32.6 million for fiscal 2018, 2017 and 2016.

11. Commitments and Contingencies

Litigation

In the normal course of business, we are subject to various legal and regulatory proceedings. For such matters, we record liabilities when they are considered probable and estimable, based on currently available facts, our historical experience, and our estimates of the ultimate outcome or resolution of the liability in the future. While the outcome of these proceedings is uncertain and a loss in excess of the amount we have accrued is possible though not reasonably estimable, it is the opinion of management that any amounts exceeding the accruals will not have a material adverse impact on our financial position, results of operations or cash flows.

We maintain liability insurance for various risks associated with the operation of our natural gas pipelines and facilities, including for property damage and bodily injury. These liability insurance policies generally require us to be responsible for the first $1.0 million (self-insured retention) of each incident.

The National Transportation Safety Board (NTSB) is investigating an incident that occurred at a Dallas, Texas residence on February 23, 2018 that resulted in one fatality and injuries to four other residents. Together with the Railroad Commission of Texas and the Pipeline and Hazardous Materials Safety Administration, Atmos Energy is a party to the investigation and in that capacity is working closely with the NTSB to help determine the cause of this incident.

On March 29, 2018, a civil action was filed in Dallas, Texas against Atmos Energy in response to the February 23rd incident. The plaintiffs seek over $1.0 million in damages for, among with others, wrongful death and personal injury.

We are a party to various other litigation or claims that have arisen in the ordinary course of our business. While the results of such litigation or claims cannot be predicted with certainty, we continue to believe the final outcome of such litigation or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Environmental Matters

We are a party to environmental matters and claims that have arisen in the ordinary course of our business. While the ultimate results of response actions to these environmental matters and claims cannot be predicted with certainty, we believe the final outcome of such response actions will not have a material adverse effect on our financial condition, results of operations or cash flows because we believe that the expenditures related to such response actions will either be recovered through rates, shared with other parties or are adequately covered by insurance.

Purchase Commitments

Our distribution and pipeline and storage segments maintain supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of the individual contract.

Our Mid-Tex Division maintains a limited number of long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at prices indexed to natural gas trading hubs. At September 30, 2018, we were committed to purchase 54.1 Bcf within one year and 37.2 Bcf within two to three years under indexed contracts. Purchases under these contracts totaled $57.2 million, $49.7 million and $85.3 million for 2018, 2017 and 2016.

Regulatory Matters

The SEC and the Commodities Futures Trading Commission, pursuant to the Dodd–Frank Act, established numerous regulations relating to U.S. financial markets. We enacted procedures and modified existing business practices and contractual arrangements to comply with such regulations. There are, however, some rulemaking proceedings that have not yet been finalized, including those relating to capital and margin rules for (non–cleared) swaps. We do not expect these rules to directly impact our business practices or collateral requirements. However, depending on the substance of these final rules, in addition to certain international regulatory requirements still under development that are similar to Dodd–Frank, our swap counterparties could be subject to additional and potentially significant capitalization requirements. These regulations could motivate counterparties to increase our collateral requirements or cash postings.

As of September 30, 2018, formula rate mechanisms were pending regulatory approval in our Mississippi and Tennessee service areas, infrastructure mechanisms were pending regulatory approval in our Mississippi service area and rate cases were pending regulatory approval in our Kentucky, Mid-Tex, Virginia and West Texas service areas. These regulatory proceedings are discussed in further detail above in the *Business — Ratemaking Activity* section. Additionally, as discussed in further detail in Note 12, all jurisdictions are addressing impacts of the TCJA.

12. Income Taxes

Impact of the Tax Cuts and Jobs Act of 2017

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the "TCJA") was signed into law. The TCJA introduced several significant changes to corporate income tax laws in the United States. The most significant change that affects Atmos Energy is the reduction of the federal statutory income tax rate from 35% to 21%. As a rate-regulated entity, the accelerated capital expensing and the limitation on interest deductibility provisions included in the TCJA are not applicable to us.

Under generally accepted accounting principles, we use the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled.

At September 30, 2017, we measured our net deferred tax liability using the enacted federal statutory tax rate of 35%. The enactment of the TCJA on December 22, 2017 required us to remeasure our deferred tax assets and liabilities, including our U.S. federal income tax net operating loss carryforwards, at the newly enacted federal statutory income tax rate of 21%. As the Company’s fiscal year end is September 30, 2018, the Internal Revenue Code requires the Company to use a blended statutory federal corporate income tax rate of 24.5% for fiscal 2018.

The decrease in the federal statutory income tax rate reduced our net deferred tax liability by $905.3 million. Of this amount, $746.5 million relates to regulated operations and has been recorded as a regulatory liability, a portion of which is currently being returned to utility customers in accordance with issued regulatory orders and the Internal Revenue Code. The remaining $158.8 million has been reflected as a one-time income tax benefit in our consolidated statement of income for the year ended September 30, 2018, because these taxes are not related to our cost of service ratemaking.

The SEC issued guidance in Staff Accounting Bulletin 118 (SAB 118), which allows us to record provisional amounts during a one-year measurement period, similar to the measurement period in accounting for business combinations. The Company has determined a reasonable estimate for the measurement and accounting for certain effects of the TCJA, including the remeasurement of our net deferred tax liabilities and the establishment of a regulatory liability, which have been reflected as provisional amounts in the September 30, 2018 consolidated financial statements. The amounts represent our best estimates based upon records, information and current guidance. We are still analyzing certain aspects of the TCJA, refining our calculations and expecting additional guidance relating to the TCJA from the U.S. Department of the Treasury and the Internal Revenue Service. Any additional guidance issued or future actions of our regulators could potentially affect the final determination of the accounting effects arising from the implementation of the TCJA.

We have and continue to work with our regulators in each jurisdiction to determine the amortization of the excess deferred taxes regulatory liability of $746.5 million of which the balance is $744.9 million as of September 30, 2018. In addition, we have recorded a cost of service regulatory liability of $22.5 million as of September 30, 2018. Accounting orders were issued for all our service areas that required us to establish, effective January 1, 2018, a separate regulatory liability for the difference in taxes included in our rates that have been calculated based on a 35% statutory income tax rate and the new 21% statutory income tax rate. The establishment of this regulatory liability relating to our cost of service rates resulted in a reduction to our revenues beginning in the second quarter of fiscal 2018.

We have received approval from regulators to update our cost of service rates to reflect the decrease in the statutory income tax rate in our Colorado, Kansas, Kentucky, Louisiana and Texas service areas. We are still working with regulators in Mississippi, Tennessee and Virginia to reflect the effects of the lower statutory income tax rate in our cost of service in rates. As of September 30, 2018, we received approval from regulators to return amounts to customers related to the regulatory liabilities recorded for differences in our cost of service rates due to change in the federal statutory income tax rate in Colorado and Kansas.

As of September 30, 2018, we received approval from regulators to return amounts to customers related to the regulatory liabilities recorded for the excess deferred taxes created upon implementation of the TCJA in Colorado, Kentucky and Louisiana in accordance with regulatory proceedings on a provisional basis over periods ranging from 18 to 40 years. In our remaining jurisdictions, the treatment of the effects of the TCJA in rates is being addressed in ongoing or will be addressed in future regulatory proceedings.

Income Tax Expense

The components of income tax expense from continuing operations for 2018, 2017 and 2016 were as follows:

	2018	2017	2016
		(In thousands)	
Current			
Federal	$ (10,099)	$ —	$ —
State	11,075	9,022	5,667
Deferred			
Federal	150,556	197,013	178,630
State	15,330	15,348	12,350
TCJA Impact	(158,782)	—	—
Investment tax credits	—	—	(5)
	$ 8,080	$ 221,383	$ 196,642

Reconciliations of the provision for income taxes computed at the statutory rate to the reported provisions for income taxes from continuing operations for 2018, 2017 and 2016 are set forth below:

	2018	2017	2016
		(In thousands)	
Tax at statutory rate(1)	$ 149,730	$ 211,433	$ 189,764
Common stock dividends deductible for tax reporting	(1,745)	(2,584)	(2,570)
State taxes (net of federal benefit)	19,826	16,100	11,133
Change in valuation allowance	—	—	1,324
Amortization of excess deferred taxes	(1,219)	—	—
Remeasurement due to TCJA	(158,782)	—	—
Other, net	270	(3,566)	(3,009)
Income tax expense	$ 8,080	$ 221,383	$ 196,642

(1) Tax expense is calculated at the statutory federal income tax rate of 24.5% for the year ended September 30, 2018 and 35% for the years ended September 30, 2017 and 2016.

Deferred income taxes reflect the tax effect of differences between the basis of assets and liabilities for book and tax purposes. The tax effect of temporary differences that gave rise to significant components of the deferred tax liabilities and deferred tax assets at September 30, 2018 and 2017 are presented below:

	2018	2017
	(In thousands)	
Deferred tax assets:		
Employee benefit plans	$ 72,745	$ 121,288
Interest rate agreements	27,135	65,171
Net operating loss carryforwards	461,481	555,043
Charitable and other credit carryforwards	6,818	18,873
Regulatory excess deferred tax	169,947	—
Other	13,804	10,218
Total deferred tax assets	751,930	770,593
Valuation allowance	(1,465)	(5,403)
Net deferred tax assets	750,465	765,190
Deferred tax liabilities:		
Difference in net book value and net tax value of assets	(1,859,787)	(2,528,485)
Pension funding	(6,986)	(13,101)
Gas cost adjustments	1,005	(60,376)
Other	(38,764)	(41,927)
Total deferred tax liabilities	(1,904,532)	(2,643,889)
Net deferred tax liabilities	$ (1,154,067)	$ (1,878,699)
Deferred credits for rate regulated entities	$ 762	$ 985

At September 30, 2018, we had $430.0 million of federal net operating loss carryforwards. The federal net operating loss carryforwards are available to offset taxable income and will begin to expire in 2029. The Company also has $10.1 million of federal alternative minimum tax credit carryforwards, which do not expire and are expected to be fully refunded to us between 2019 and 2022 as a result of changes introduced by the TCJA. These credit carryforwards are now reflected as taxes receivable within the deferred charges and other assets line item on our consolidated balance sheet. In addition, the Company has $5.3 million in remeasured charitable contribution carryforwards to offset future taxable income. The Company's charitable contribution carryforwards expiration period begins in 2019.

The Company also has $31.4 million of state net operating loss carryforwards (net of $8.4 million of remeasured federal effects) and $1.5 million of state tax credits carryforwards (net of $0.4 million of remeasured federal effects). Depending on the jurisdiction in which the state net operating loss was generated, the carryforwards expiration period begins in 2019.

Due to the changes introduced by the TCJA, we now believe it is more likely than not that the benefit from certain charitable contribution carryforwards for which a valuation allowance was previously established will be realized. As a result, we reduced our valuation allowance by $4.2 million during the first quarter of fiscal 2018. This amount is included in the $158.8 million one-time income tax benefit.

We believe it is more likely than not that the benefit from certain state net operating loss carryforwards and state credit carryforwards will not be realized. Due to the uncertainty of realizing a benefit from the deferred tax asset recorded for the carryforwards, a re-measured valuation allowance of $1.5 million continues to be established for the year ended September 30, 2018. No additional valuation allowance was recorded for the year ended September 30, 2018.

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At September 30, 2018, we had recorded liabilities associated with unrecognized tax benefits totaling $26.2 million. The following table reconciles the beginning and ending balance of our unrecognized tax benefits:

	2018	2017	2016
		(In thousands)	
Unrecognized tax benefits - beginning balance	$ 23,719	$ 20,298	$ 17,069
Increase (decrease) resulting from prior period tax positions	22	(366)	(290)
Increase resulting from current period tax positions	2,462	3,787	3,519
Unrecognized tax benefits - ending balance	26,203	23,719	20,298
Less: deferred federal and state income tax benefits	(5,503)	(8,302)	(7,104)
Total unrecognized tax benefits that, if recognized, would impact the effective income tax rate as of the end of the year	$ 20,700	$ 15,417	$ 13,194

The Company recognizes interest accrued related to unrecognized tax benefits in interest expense and penalties included within interest charges in our consolidated statement of income. During the years ended September 30, 2018, 2017 and 2016, the Company recognized approximately $1.6 million, $1.1 million and $2.5 million in interest and penalties. The Company had approximately $6.1 million, $4.5 million and $3.3 million for the payment of interest and penalties accrued at September 30, 2018, 2017 and 2016.

We file income tax returns in the U.S. federal jurisdiction as well as in various states where we have operations. We have concluded substantially all U.S. federal income tax matters through fiscal year 2009 and concluded substantially all Texas income tax matters through fiscal year 2010.

13. Financial Instruments

We use financial instruments to mitigate commodity price risk and interest rate risk. Our financial instruments do not contain any credit-risk-related or other contingent features that could cause accelerated payments when our financial instruments are in net liability positions.

As discussed in Note 2 and Note 15, we report our financial instruments as risk management assets and liabilities, each of which is classified as current or noncurrent based upon the anticipated settlement date of the underlying financial instrument. The following table shows the fair values of our risk management assets and liabilities at September 30, 2018 and 2017.

	September 30	
	2018	2017
	(In thousands)	
Assets from risk management activities, current	$ 1,369	$ 2,436
Assets from risk management activities, noncurrent	250	803
Liabilities from risk management activities, current	(56,734)	(322)
Liabilities from risk management activities, noncurrent	(103)	(112,076)
Net assets (liabilities)	$ (55,218)	$ (109,159)

Commodity Risk Management Activities

Our purchased gas cost adjustment mechanisms essentially insulate our distribution segment from commodity price risk; however, our customers are exposed to the effects of volatile natural gas prices. We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season.

Our distribution gas supply department is responsible for executing this segment’s commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2017-2018 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 26 percent, or approximately 15.0 Bcf of the winter flowing gas requirements at a weighted average cost of approximately $3.20 per Mcf. We have not designated these financial instruments as hedges for accounting purposes.

Interest Rate Risk Management Activities

We currently manage interest rate risk through the use of forward starting interest rate swaps to fix the Treasury yield component of the interest cost associated with anticipated financings.

In October 2012, we entered into forward starting interest rate swaps to fix the Treasury yield component associated with $210 million of the then anticipated issuance of $250 million unsecured senior notes in fiscal 2017. These notes were issued as planned in June 2017 and we settled swaps with the payment of $37.0 million. Because the swaps were effective, the realized loss was recorded as a component of accumulated other comprehensive income (loss) and is being recognized as a component of interest expense over the 27-year life of the senior notes.

Additionally, in fiscal 2014 and 2015, we entered into forward starting interest rate swaps to effectively fix the Treasury yield component associated with $450 million of the anticipated issuance of $450 million unsecured senior notes in fiscal 2019. We designated all of these swaps as cash flow hedges at the time the agreements were executed. Accordingly, unrealized gains and losses associated with the forward starting interest rate swaps will be recorded as a component of accumulated other comprehensive income (loss). When the forward starting interest rate swaps settle, the realized gain or loss will be recorded as a component of accumulated other comprehensive income (loss) and recognized as a component of interest expense over the life of the related financing arrangement. Hedge ineffectiveness to the extent incurred, will be reported as a component of interest expense.

Prior to fiscal 2012, we entered into several interest rate agreements to fix the Treasury yield component of the interest cost of financing for various issuances of long-term debt and senior notes. The gains and losses realized upon settlement of these interest rate agreements were recorded as a component of accumulated other comprehensive income (loss) when they were settled and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for the settled interest rate agreements extend through fiscal 2045.

Quantitative Disclosures Related to Financial Instruments

The following tables present detailed information concerning the impact of financial instruments on our consolidated balance sheet and income statements.

As of September 30, 2018, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of September 30, 2018, we had 22,874 MMcf of net long commodity contracts outstanding. These contracts have not been designated as hedges.

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments as of September 30, 2018 and 2017. The gross amounts of recognized assets and liabilities are netted within our Consolidated Balance Sheets to the extent that we have netting arrangements with the counterparties.

	Balance Sheet Location	Assets	Liabilities
		(In thousands)	
September 30, 2018			
Designated As Hedges:			
Interest rate swap agreements	Other current assets / Other current liabilities	$ —	$ (56,499)
Total		—	(56,499)
Not Designated As Hedges:			
Commodity contracts	Other current assets / Other current liabilities	1,369	(235)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	250	(103)
Total		1,619	(338)
Gross Financial Instruments		1,619	(56,837)
Gross Amounts Offset on Consolidated Balance Sheet:			
Contract netting		—	—
Net Financial Instruments		1,619	(56,837)
Cash collateral		—	—
Net Assets/Liabilities from Risk Management Activities		$ 1,619	$ (56,837)

	Balance Sheet Location	Assets	Liabilities
		(In thousands)	
September 30, 2017			
Designated As Hedges:			
Interest rate swap agreements	Deferred charges and other assets / Deferred credits and other liabilities	$ —	$ (112,076)
Total		—	(112,076)
Not Designated As Hedges:			
Commodity contracts	Other current assets / Other current liabilities	2,436	(322)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	803	—
Total		3,239	(322)
Gross Financial Instruments		3,239	(112,398)
Gross Amounts Offset on Consolidated Balance Sheet:			
Contract netting		—	—
Net Financial Instruments		3,239	(112,398)
Cash collateral		—	—
Net Assets/Liabilities from Risk Management Activities		$ 3,239	$ (112,398)

Impact of Financial Instruments on the Income Statement

Cash Flow Hedges

As discussed above, our distribution segment has interest rate swap agreements, which we designated as a cash flow hedge at the time the swaps were executed. The net loss on settled interest rate agreements reclassified from AOCI into interest charges on our consolidated income statements for the years ended September 30, 2018, 2017 and 2016 was $(2.4) million, $(1.0) million and $(0.5) million.

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the years ended September 30, 2018 and 2017. The amounts included in the table below exclude gains and losses arising from ineffectiveness because these amounts are immediately recognized in the income statement as incurred.

	Fiscal Year Ended September 30	
	2018	2017
	(In thousands)	
Increase in fair value:		
Interest rate agreements	$ 43,184	$ 74,560
Forward commodity contracts[(1)]	—	9,847
Recognition of (gains) losses in earnings due to settlements:		
Interest rate agreements	1,752	662
Forward commodity contracts[(1)]	—	(4,865)
Total other comprehensive income from hedging, net of tax[(2)]	$ 44,936	$ 80,204

(1) Due to the sale of AEM, these amounts are included in income from discontinued operations
(2) Utilizing an income tax rate of approximately 23 percent for fiscal 2018 and an income tax rate ranging from approximately 37 percent to 39 percent for fiscal 2017 based on the effective rates in each taxing jurisdiction.

Deferred gains (losses) recorded in AOCI associated with our interest rate agreements are recognized in earnings as they are amortized. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred gains (losses) recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of September 30, 2018. However, the table below does not include the expected recognition in earnings of our outstanding interest rate agreements as those financial instruments have not yet settled.

	Interest Rate Agreements
	(In thousands)
2019	$ (1,863)
2020	(1,893)
2021	(1,893)
2022	(1,893)
2023	(1,893)
Thereafter	(38,729)
Total(1)	$ (48,164)

(1) Utilizing an income tax rate of approximately 23 percent.

Financial Instruments Not Designated as Hedges

As discussed above, financial instruments used in our distribution segment are not designated as hedges. However, there is no earnings impact on our distribution segment as a result of the use of these financial instruments because the gains and losses arising from the use of these financial instruments are recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue. Accordingly, the impact of these financial instruments is excluded from this presentation.

14. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2.

Fair value measurements also apply to the valuation of our pension and post-retirement plan assets. The fair value of these assets is presented in Note 7.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2018 and 2017. As required under authoritative accounting literature, assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)(1)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral	September 30, 2018
			(In thousands)		
Assets:					
Financial instruments	$ —	$ 1,619	$ —	$ —	$ 1,619
Available-for-sale securities					
Registered investment companies	42,644	—	—	—	42,644
Bond mutual funds	21,507	—	—	—	21,507
Bonds	—	31,400	—	—	31,400
Money market funds	—	3,834	—	—	3,834
Total available-for-sale securities	64,151	35,234	—	—	99,385
Total assets	$ 64,151	$ 36,853	$ —	$ —	$ 101,004
Liabilities:					
Financial instruments	$ —	$ 56,837	$ —	$ —	$ 56,837

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)(1)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral	September 30, 2017
			(In thousands)		
Assets:					
Financial instruments	$ —	$ 3,239	$ —	$ —	$ 3,239
Available-for-sale securities					
Registered investment companies	41,097	—	—	—	41,097
Bond mutual funds	16,371	—	—	—	16,371
Bonds	—	29,104	—	—	29,104
Money market funds	—	1,837	—	—	1,837
Total available-for-sale securities	57,468	30,941	—	—	88,409
Total assets	$ 57,468	$ 34,180	$ —	$ —	$ 91,648
Liabilities:					
Financial instruments	$ —	$ 112,398	$ —	$ —	$ 112,398

(1) Our Level 2 measurements consist of over-the-counter options and swaps, which are valued using a market-based approach in which observable market prices are adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences, municipal and corporate bonds, which are valued based on the most recent available quoted market prices and money market funds which are valued at cost.

Available-for-sale securities, which include debt and equity securities, are comprised of the following:

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of September 30, 2018				
Domestic equity mutual funds	$ 26,950	$ 9,363	$ (353)	$ 35,960
Foreign equity mutual funds	4,656	2,028	—	6,684
Bond mutual funds	21,810	—	(303)	21,507
Bonds	31,511	13	(124)	31,400
Money market funds	3,834	—	—	3,834
	$ 88,761	$ 11,404	$ (780)	$ 99,385
As of September 30, 2017				
Domestic equity mutual funds	$ 25,361	$ 8,920	$ —	$ 34,281
Foreign equity mutual funds	4,581	2,235	—	6,816
Bond mutual funds	16,391	2	(22)	16,371
Bonds	29,074	46	(16)	29,104
Money market funds	1,837	—	—	1,837
	$ 77,244	$ 11,203	$ (38)	$ 88,409

At September 30, 2018 and 2017, our available-for-sale securities included $46.5 million and $42.9 million related to assets held in separate rabbi trusts for our supplemental executive retirement plans as discussed in Note 7. At September 30, 2018 we maintained investments in bonds that have contractual maturity dates ranging from October 2018 through September 2021.

Other Fair Value Measures

In addition to the financial instruments above, we have several financial and nonfinancial assets and liabilities subject to fair value measures. These financial assets and liabilities include cash and cash equivalents, accounts receivable, accounts payable and debt. The nonfinancial assets and liabilities include asset retirement obligations and pension and post-retirement plan assets. We record cash and cash equivalents, accounts receivable, accounts payable and debt at carrying value. For cash and cash equivalents, accounts receivable and accounts payable, we consider carrying value to materially approximate fair value due to the short-term nature of these assets and liabilities.

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations, which are considered Level 1 fair value measurements for debt instruments with a recent, observable trade or Level 2 fair value measurements for debt instruments where fair value is determined using the most recent available quoted market price. The following table presents the carrying value and fair value of our debt as of September 30, 2018:

	September 30, 2018
	(In thousands)
Carrying Amount	$ 3,085,000
Fair Value	$ 3,161,679

15. Discontinued Operations

On October 29, 2016, we entered into a Membership Interest Purchase Agreement (the Agreement) with CenterPoint Energy Services, Inc., a subsidiary of CenterPoint Energy, Inc. (CES) to sell all of the equity interests of AEM. The transaction closed on January 3, 2017, with an effective date of January 1, 2017. CES paid a cash purchase price of $38.3 million plus working capital of $109.0 million for total cash consideration of $147.3 million. Of this amount, $7.0 million was placed into escrow, to be paid to the Company within 24 months, net of any indemnification claims agreed upon between the two companies. In January 2018, $3.0 million of this escrowed amount was released and received by the Company. We recognized a net gain of $0.03 per diluted share on the sale in the second quarter of fiscal 2017 and completed the working capital true–up during the third quarter of fiscal 2017.

The operating results of our natural gas marketing reportable segment have been reported on the consolidated statements of income as income from discontinued operations, net of income tax for the years ended September 30, 2017 and 2016. Accordingly, expenses related to allocable general corporate overhead and interest expense are not included in these results. The decision to report this segment as a discontinued operation was predicated, in part, on the following qualitative and quantitative factors: 1) the disposal resulted in the company becoming a fully regulated entity; 2) the fact that an entire reportable segment was disposed and 3) the fact the disposed segment represented in excess of 30 percent of consolidated revenues over the last five fiscal years.

The tables below set forth selected financial information related to discontinued operations. Operating expenses include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income. At September 30, 2018 and 2017 we did not have any assets or liabilities held for sale.

The following table presents statement of income data related to discontinued operations.

	Year Ended September 30	
	2017	2016
	(In thousands)	
Operating revenues	$ 303,474	$ 1,005,090
Purchased gas cost	277,554	968,118
Operating expenses	7,874	26,184
Operating income	18,046	10,788
Other nonoperating expense	(211)	(2,495)
Income from discontinued operations before income taxes	17,835	8,293
Income tax expense	6,841	3,731
Income from discontinued operations	10,994	4,562
Gain on sale from discontinued operations, net of tax ($10,215 and $0)	2,716	—
Net income from discontinued operations	$ 13,710	$ 4,562

The following table presents statement of cash flow data related to discontinued operations.

	Year Ended September 30	
	2017	2016
	(In thousands)	
Depreciation and amortization	$ 185	$ 2,304
Capital expenditures	$ —	$ 321
Non-cash loss in commodity contract cash flow hedges	$ (8,165)	$ (33,533)

Significant Accounting Policies Related to Discontinued Operations

Except as noted below, AEM adhered to the same Significant Accounting Policies as described in Note 2.

Revenue recognition — Operating revenues for our natural gas marketing segment were recognized in the period in which actual volumes were transported and storage services were provided. Operating revenues for our natural gas marketing segment and the associated carrying value of natural gas inventory (inclusive of storage costs) were recognized when we sold the gas and physically delivered it to our customers. Operating revenues include realized gains and losses arising from the settlement of financial instruments used in our natural gas marketing activities.

Gas stored underground — Gas stored underground was comprised of natural gas injected into storage to conduct the operations of the natural gas marketing segment. Our natural gas marketing segment utilized the average cost method; however, most of this inventory was hedged and was therefore reported at fair value at the end of each month.

Property, plant and equipment — Natural gas marketing property, plant and equipment was stated at cost. Depreciation was generally computed on the straight-line method for financial reporting purposes based upon estimated useful lives ranging from 3 to 30 years.

Financial instruments and hedging activities — In our natural gas marketing segment, we previously designated most of the natural gas inventory held by this operating segment as the hedged item in a fair-value hedge. This inventory was marked to market at the end of each month based on the Gas Daily index, with changes in fair value recognized as unrealized gains or losses in purchased gas cost, which is reflected in income from discontinued operations in the period of change. The financial instruments associated with this natural gas inventory were designated as fair-value hedges and were marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains or losses in purchased gas cost in the period of change. We elected to exclude this spot/forward differential for purposes of assessing the effectiveness of these fair-value hedges.

Additionally, we previously elected to treat fixed-price forward contracts used in our natural gas marketing segment to deliver natural gas as normal purchases and normal sales. As such, these deliveries were recorded on an accrual basis in accordance with our revenue recognition policy. Financial instruments used to mitigate the commodity price risk associated with these contracts were designated as cash flow hedges of anticipated purchases and sales at indexed prices. Accordingly, unrealized gains and losses on these open financial instruments were recorded as a component of accumulated other comprehensive income, and were recognized in earnings as a component of purchased gas cost which is reflected in income from discontinued operations when the hedged volumes were sold.

Gains and losses from hedge ineffectiveness were recognized in the income statement. Fair value and cash flow hedge ineffectiveness arising from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the financial instruments is referred to as basis ineffectiveness. Ineffectiveness arising from changes in the fair value of the fair value hedges due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity is referred to as timing ineffectiveness. Hedge ineffectiveness, to the extent incurred, is reported as a component of purchased gas cost reflected in income from discontinued operations for the years ended September 30, 2017 and 2016.

Our natural gas marketing segment also utilized master netting agreements with significant counterparties that allow us to offset gains and losses arising from financial instruments that would be settled in cash with gains and losses arising from financial instruments that could be settled with the physical commodity. Assets and liabilities from risk management activities, as well as accounts receivable and payable, reflect the master netting agreements in place. Additionally, the accounting guidance for master netting arrangements requires us to include the fair value of cash collateral or the obligation to return cash in the amounts that have been netted under master netting agreements used to offset gains and losses arising from financial instruments.

Fair Value Measurements — Our discontinued operations used the same fair value measurement policies as described in Note 2 for our continuing operations. Level 1 measurements included primarily exchange-traded financial instruments and gas stored underground that was been designated as the hedged item in a fair value hedge. Within our natural gas marketing operations, we utilized a mid-market pricing convention (the mid-point between the bid and ask prices), as permitted under current accounting standards. Values derived from these sources reflected the market in which transactions involving these financial instruments are executed. Level 2 measurements primarily consisted of non-exchange-traded financial instruments, such as over-the-counter options and swaps.

Short-term Debt Related to Discontinued Operations

AEM had one uncommitted $25 million 364-day bilateral credit facility that was scheduled to expire on July 31, 2017 and one committed $15 million 364-day bilateral credit facility that was scheduled to expire on September 30, 2017. In connection with the sale of AEM, both facilities were terminated on January 3, 2017.

Commodity Risk Management Activities

Our discontinued natural gas marketing segment was exposed to risks associated with changes in the market price of natural gas through the purchase, sale and delivery of natural gas to its customers at competitive prices. Through December 31, 2016, we managed our exposure to such risks through a combination of physical storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Effective January 1, 2017, as a result of the sale of AEM, these activities were discontinued.

Due to the sale of AEM, we determined that the cash flows associated with our natural gas marketing commodity cash flow hedges were no longer probable of occurring; therefore, we discontinued hedge accounting as of December 31, 2016. As a result, we reclassified the gain in accumulated other comprehensive income associated with the commodity contracts into earnings as a reduction of purchased gas cost and recognized a pre-tax gain of $10.6 million, which is included in income from discontinued operations on the consolidated statement of income for the year ended September 30, 2017.

The Company's other risk management activities are discussed in Note 13.

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our natural gas marketing segment was recorded as a component of purchased gas cost, which is included in discontinued operations on the consolidated statements of income, and primarily results from differences in the location and timing of the derivative instrument and the hedged item. For the years ended September 30, 2017 and 2016, we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $3.4 million and $21.6 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of our natural gas marketing segment commodity contracts designated as fair value hedges and the related hedged item on the results of discontinued operations on our consolidated income statement for the years ended September 30, 2017 and 2016 is presented below.

	Year Ended September 30	
	2017	2016
	(In thousands)	
Commodity contracts	$ (9,567)	$ 3,516
Fair value adjustment for natural gas inventory designated as the hedged item	12,858	18,079
Total decrease in purchased gas cost reflected in income from discontinued operations	$ 3,291	$ 21,595
The decrease in purchased gas cost reflected in income from discontinued operations is comprised of the following:		
Basis ineffectiveness	$ (597)	$ (1,390)
Timing ineffectiveness	3,888	22,985
	$ 3,291	$ 21,595

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot-to-forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on purchased gas cost.

Cash Flow Hedges

The impact of our natural gas marketing segment cash flow hedges on our consolidated income statements for the years ended September 30, 2017 and 2016 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transactions. Therefore, this presentation is not indicative of the economic margin we realized when the underlying physical and financial transactions were settled.

	Year Ended September 30	
	2017	2016
	(In thousands)	
Loss reclassified from AOCI for effective portion of natural gas marketing commodity contracts	$ (2,612)	$ (52,651)
Gain (loss) arising from ineffective portion of natural gas marketing commodity contracts	111	(19)
Gain on discontinuance of cash flow hedging of natural gas marketing commodity contracts reclassified from AOCI	10,579	—
Total impact on purchased gas cost reflected in income from discontinued operations	$ 8,078	$ (52,670)

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our consolidated income statements for the years ended September 30, 2017 and 2016 was an increase (decrease) in purchased gas cost reflected in income from discontinued operations of $(6.8) million and $15.5 million, which is included in discontinued operations on the consolidated statements of income. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic margin we realized when the underlying physical and financial transactions were settled.

16. Concentration of Credit Risk

Credit risk is the risk of financial loss to us if a customer fails to perform its contractual obligations. We engage in transactions for the purchase and sale of products and services with major companies in the energy industry and with industrial, commercial, residential and municipal energy consumers. These transactions principally occur in the southern and midwestern regions of the United States. We believe that this geographic concentration does not contribute significantly to our overall exposure to credit risk. Credit risk associated with trade accounts receivable for the distribution segment is mitigated by the large number of individual customers and the diversity in our customer base. The credit risk for our other segment is not significant.

17. Selected Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below. The sum of net income per share by quarter may not equal the net income per share for the fiscal year due to variations in the weighted average shares outstanding used in computing such amounts. Our businesses are seasonal due to weather conditions in our service areas. For further information on its effects on quarterly results, see the "Results of Operations" discussion included in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section herein.

	Quarter Ended			
	December 31	March 31	June 30	September 30
	(In thousands, except per share data)			
Fiscal year 2018:				
Operating revenues				
Distribution	$ 860,792	$ 1,199,291	$ 535,488	$ 407,476
Pipeline and storage	126,463	120,955	127,633	132,662
Intersegment eliminations	(98,063)	(100,837)	(100,876)	(95,438)
Total operating revenues	889,192	1,219,409	562,245	444,700
Purchased gas cost	366,917	626,960	130,886	43,085
Operating income	241,561	268,988	122,993	89,592
Net Income	314,132	178,992	71,193	38,747
Basic and diluted earnings per share				
Net income per share — basic and diluted	$ 2.89	$ 1.60	$ 0.64	$ 0.35

	Quarter Ended			
	December 31	March 31	June 30	September 30
	(In thousands, except per share data)			
Fiscal year 2017:				
Operating revenues				
Distribution	$ 754,656	$ 962,541	$ 494,060	$ 437,918
Pipeline and storage	109,952	111,972	117,283	117,823
Intersegment eliminations	(84,440)	(86,327)	(84,842)	(90,861)
Total operating revenues	780,168	988,186	526,501	464,880
Purchased gas cost	311,305	427,494	114,176	72,561
Operating income	209,918	285,172	140,664	91,792
Income from continuing operations	114,038	162,012	70,808	35,853
Income from discontinued operations	10,994	—	—	—
Gain on sale of discontinued operations	—	2,716	—	—
Net Income	125,032	164,728	70,808	35,853
Basic and diluted earnings per share				
Income per share from continuing operations	$ 1.08	$ 1.52	$ 0.67	$ 0.34
Income per share from discontinued operations	0.11	0.03	—	—
Net income per share — basic and diluted	$ 1.19	$ 1.55	$ 0.67	$ 0.34

ITEM 9. ***Changes in and Disagreements With Accountants on Accounting and Financial Disclosure.***

None.

ITEM 9A. ***Controls and Procedures.***

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of September 30, 2018 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f), in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (COSO). Based on our evaluation under the framework in *Internal Control-Integrated Framework* issued by COSO and applicable Securities and Exchange Commission rules, our management concluded that our internal control over financial reporting was effective as of September 30, 2018, in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Ernst & Young LLP has issued its report on the effectiveness of the Company's internal control over financial reporting. That report appears below.

/s/ MICHAEL E. HAEFNER	/s/ CHRISTOPHER T. FORSYTHE
Michael E. Haefner	Christopher T. Forsythe
President, Chief Executive Officer and Director	Senior Vice President and Chief Financial Officer

November 13, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Atmos Energy Corporation

Opinion on Internal Control over Financial Reporting

We have audited Atmos Energy Corporation's internal control over financial reporting as of September 30, 2018, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Atmos Energy Corporation (the Company) maintained, in all material respects, effective internal control over financial reporting as of September 30, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the 2018 consolidated financial statements of the Company and our report dated November 13, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Ernst & Young LLP

Dallas, Texas
November 13, 2018

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Act) during the fourth quarter of the fiscal year ended September 30, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. *Other Information.*

Not applicable.

PART III

ITEM 10. *Directors, Executive Officers and Corporate Governance.*

Information regarding directors and compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 6, 2019. Information regarding executive officers is reported below:

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information as of September 30, 2018, regarding the executive officers of the Company. It is followed by a brief description of the business experience of each executive officer.

Name	Age	Years of Service	Office Currently Held
Kim R. Cocklin	67	12	Executive Chairman of the Board
Michael E. Haefner	58	10	President, Chief Executive Officer and Director
Christopher T. Forsythe	47	15	Senior Vice President and Chief Financial Officer
David J. Park	47	14	Senior Vice President, Utility Operations
John K. Akers	55	27	Senior Vice President, Safety and Enterprise Services
Karen E. Hartsfield	48	3	Senior Vice President, General Counsel and Corporate Secretary
John M. Robbins	48	5	Senior Vice President, Human Resources

Kim R. Cocklin was named Executive Chairman of the Board on October 1, 2017. From October 1, 2010 through September 30, 2015, Mr. Cocklin served the Company as President and Chief Executive Officer and from October 1, 2015 through September 30, 2017, as Chief Executive Officer. Mr. Cocklin joined the Company in June 2006 and served as President and Chief Operating Officer of the Company from October 1, 2008 through September 30, 2010, after having served as Senior Vice President, Regulated Operations from October 2006 through September 2008. Mr. Cocklin was appointed to the Board of Directors on November 10, 2009.

Michael E. Haefner was named President and Chief Executive Officer, effective October 1, 2017. Mr. Haefner joined the Company in June 2008 as Senior Vice President, Human Resources. On January 19, 2015, Mr. Haefner was promoted to Executive Vice President and assumed oversight responsibility for Atmos Pipeline - Texas, Atmos Energy Holdings, Inc. and the gas supply and services function. On October 1, 2015, Mr. Haefner was promoted to the role of President and Chief Operating Officer in which he also assumed oversight responsibility for the operations of our six utility divisions and customer service. Mr. Haefner was appointed to the Board of Directors on November 4, 2015.

Christopher T. Forsythe was named Senior Vice President and Chief Financial Officer effective February 1, 2017. Mr. Forsythe joined the Company in June 2003 and prior to his promotion, served as the Company's Vice President and Controller from May 2009 through January 2017.

David J. Park was named Senior Vice President of Utility Operations, effective January 1, 2017. In this role, Mr. Park is responsible for the operations of Atmos Energy's six utility divisions as well as gas supply. Prior to this promotion, Mr. Park served as the President of the West Texas Division from July 2012 to December 2016. Mr. Park also served as Vice President of Rates and Regulatory Affairs in the Mid-Tex Division and previously held positions in Engineering and Public Affairs. Prior to joining Atmos Energy in 2004, Mr. Park had 10 years of experience in the industry.

John K. (Kevin) Akers was named Senior Vice President, Safety and Enterprise Services, effective January 1, 2017. In this role, Mr. Akers is responsible for customer service, facilities management, safety and supply chain management. Mr. Akers joined the company in 1991. Mr. Akers assumed increased responsibilities over time and was named President of the Mississippi Division in 2002. He was later named President of the Kentucky/Mid-States Division in May 2007, a position he held until December 2016.

Karen E. Hartsfield was named Senior Vice President, General Counsel and Corporate Secretary of Atmos Energy, effective August 7, 2017. Ms. Hartsfield joined the Company in June 2015, after having served in private practice for 19 years, most recently as Managing Partner of Jackson Lewis LLP in its Dallas office from July 2013 to June 2015. Prior to joining Jackson Lewis as a partner in January 2009, Ms. Hartsfield was a partner with Baker Botts LLP in Dallas.

John M. (Matt) Robbins was named Senior Vice President, Human Resources, effective January 1, 2017. Mr. Robbins joined the Company in May 2013 and prior to this promotion served as Vice President, Human Resources from February 2015 to December 2016. Before joining Atmos Energy, Matt had over 20 years of experience in human resources.

Identification of the members of the Audit Committee of the Board of Directors as well as the Board of Directors' determination as to whether one or more audit committee financial experts are serving on the Audit Committee of the Board of Directors is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 6, 2019.

The Company has adopted a code of ethics for its principal executive officer, principal financial officer and principal accounting officer. Such code of ethics is represented by the Company's Code of Conduct, which is applicable to all directors, officers and employees of the Company, including the Company's principal executive officer, principal financial officer and principal accounting officer. A copy of the Company's Code of Conduct is posted on the Company's website at *www.atmosenergy.com* under "Corporate Responsibility." In addition, any amendment to or waiver granted from a provision of the Company's Code of Conduct will be posted on the Company's website under "Corporate Responsibility."

ITEM 11. *Executive Compensation.*

Information on executive compensation is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 6, 2019.

ITEM 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*

Security ownership of certain beneficial owners and of management is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 6, 2019. Information concerning our equity compensation plans is provided in Part II, Item 5, "Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities", of this Annual Report on Form 10-K.

ITEM 13. *Certain Relationships and Related Transactions, and Director Independence.*

Information on certain relationships and related transactions as well as director independence is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 6, 2019.

ITEM 14. *Principal Accountant Fees and Services.*

Information on our principal accountant's fees and services is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 6, 2019.

PART IV

ITEM 15. *Exhibits and Financial Statement Schedules.*

(a) 1. and 2. *Financial statements and financial statement schedules.*

The financial statements and financial statement schedule listed in the Index to Financial Statements in Item 8 are filed as part of this Form 10-K.

3. *Exhibits*

Exhibit Number	Description	Page Number or Incorporation by Reference to
	Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession	
2.1	Membership Interest Purchase Agreement by and between Atmos Energy Holdings, Inc. as Seller and CenterPoint Energy Services, Inc. as Buyer, dated as of October 29, 2016	Exhibit 2.1 to Form 8-K dated October 29, 2016 (File No. 1-10042)
	Articles of Incorporation and Bylaws	
3.1	Restated Articles of Incorporation of Atmos Energy Corporation - Texas (As Amended Effective February 3, 2010)	Exhibit 3.1 to Form 10-Q dated March 31, 2010 (File No. 1-10042)
3.2	Restated Articles of Incorporation of Atmos Energy Corporation - Virginia (As Amended Effective February 3, 2010)	Exhibit 3.2 to Form 10-Q dated March 31, 2010 (File No. 1-10042)
3.3	Amended and Restated Bylaws of Atmos Energy Corporation (as of September 28, 2015)	Exhibit 3.1 to Form 8-K dated September 28, 2015 (File No. 1-10042)
	Instruments Defining Rights of Security Holders, Including Indentures	
4.1	Specimen Common Stock Certificate (Atmos Energy Corporation)	Exhibit 4.1 to Form 10-K for fiscal year ended September 30, 2012 (File No. 1-10042)
4.2	Indenture dated as of November 15, 1995 between United Cities Gas Company and Bank of America Illinois, Trustee	Exhibit 4.11(a) to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.3	Indenture dated as of July 15, 1998 between Atmos Energy Corporation and U.S. Bank Trust National Association, Trustee	Exhibit 4.8 to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.4	Indenture dated as of May 22, 2001 between Atmos Energy Corporation and SunTrust Bank, Trustee	Exhibit 99.3 to Form 8-K dated May 15, 2001 (File No. 1-10042)
4.5	Indenture dated as of June 14, 2007, between Atmos Energy Corporation and U.S. Bank National Association, Trustee	Exhibit 4.1 to Form 8-K dated June 11, 2007 (File No. 1-10042)
4.6	Indenture dated as of March 23, 2009 between Atmos Energy Corporation and U.S. Bank National Corporation, Trustee	Exhibit 4.1 to Form 8-K dated March 26, 2009 (File No. 1-10042)
4.7(a)	Debenture Certificate for the 6 3/4% Debentures due 2028	Exhibit 99.2 to Form 8-K dated July 22, 1998 (File No. 1-10042)
4.7(b)	Global Security for the 5.95% Senior Notes due 2034	Exhibit 10(2)(g) to Form 10-K for fiscal year ended September 30, 2004 (File No. 1-10042)
4.7(c)	Global Security for the 8.50% Senior Notes due 2019	Exhibit 4.2 to Form 8-K dated March 26, 2009 (File No. 1-10042)
4.7(d)	Global Security for the 5.5% Senior Notes due 2041	Exhibit 4.2 to Form 8-K dated June 10, 2011 (File No. 1-10042)
4.7(e)	Global Security for the 4.15% Senior Notes due 2043	Exhibit 4.2 to Form 8-K dated January 8, 2013 (File No. 1-10042)
4.7(f)	Global Security for the 4.125% Senior Notes due 2044	Exhibit 4.2 to Form 8-K dated October 15, 2014 (File No. 1-10042)

4.7(g)	Global Security for the 3.000% Senior Notes due 2027	Exhibit 4.2 to Form 8-K dated June 8, 2017 (File No. 1-10042)
4.7(h)	Global Security for the 4.125% Senior Notes due 2044	Exhibit 4.3 to Form 8-K dated June 8, 2017 (File No. 1-10042)
4.7(i)	Global Security for the 4.300% Senior Notes due 2048	Exhibit 4.2 to Form 8-K dated October 4, 2018 (File No. 1-10042)
4.7(j)	Global Security for the 4.300% Senior Notes due 2048	Exhibit 4.3 to Form 8-K dated October 4, 2018 (File No. 1-10042)
	Material Contracts	
10.1(a)	Revolving Credit Agreement, dated as of September 25, 2015 among Atmos Energy Corporation, the Lenders from time to time parties thereto, Crédit Agricole Corporate and Investment Bank as Administrative Agent, and Mizuho Bank Ltd., as Syndication Agent	Exhibit 10.1 to Form 8-K dated October 1, 2015 (File No. 1-10042)
10.1(b)	First Amendment to Revolving Credit Agreement, dated as of October 5, 2016, by and among Atmos Energy Corporation, the lenders from time to time parties thereto (the "Lenders") and Credit Agricole Corporate and Investment Bank, in its capacity as administrative agent for the Lenders	Exhibit 10.1 to Form 8-K dated October 5, 2016 (File No. 1-10042)
10.1(c)	Second Amendment to Revolving Credit Agreement, dated as of September 7, 2017, by and among Atmos Energy Corporation, the lenders from time to time parties thereto (the "Lenders") and Credit Agricole Corporate and Investment Bank, in its capacity as administrative agent for the Lenders	
10.1(d)	Term Loan Agreement, dated as of September 22, 2016, by and among Atmos Energy Corporation, the Lenders from time to time parties thereto and Branch Banking and Trust Company as Administrative Agent	Exhibit 10.1 to Form 8-K dated September 22, 2016 (File No. 1-10042)
10.1(e)	First Amendment to Term Loan Agreement, dated as of September 7, 2017, by and among Atmos Energy Corporation, the lenders from time to time parties thereto (the "Lenders") and Branch Banking and Trust Company, in its capacity as administrative agent for the Lenders	
10.2	Equity Distribution Agreement, dated as of November 14, 2017, among Atmos Energy Corporation, Goldman, Sachs & Co. LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Morgan Stanley & Co. LLC and J.P. Morgan Securities LLC	Exhibit 1.1 to Form 8-K dated November 14, 2017 (File No. 1-10042)
	Executive Compensation Plans and Arrangements	
10.3(a)*	Form of Atmos Energy Corporation Change in Control Severance Agreement - Tier I	Exhibit 10.7(a) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.3(b)*	Form of Atmos Energy Corporation Change in Control Severance Agreement - Tier II	Exhibit 10.7(b) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.4(a)*	Atmos Energy Corporation Executive Retiree Life Plan	Exhibit 10.31 to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)

10.4(b)*	Amendment No. 1 to the Atmos Energy Corporation Executive Retiree Life Plan	Exhibit 10.31(a) to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.5*	Atmos Energy Corporation Annual Incentive Plan for Management (as amended and restated October 1, 2016)	Exhibit 10.5 to Form 10-K for fiscal year ended September 30, 2016 (File No. 1-10042)
10.6(a)*	Atmos Energy Corporation Supplemental Executive Benefits Plan, Amended and Restated in its Entirety August 7, 2007	Exhibit 10.8(a) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)
10.6(b)*	Form of Individual Trust Agreement for the Supplemental Executive Benefits Plan	Exhibit 10.3 to Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042)
10.7(a)*	Atmos Energy Corporation Supplemental Executive Retirement Plan (As Amended and Restated, Effective as of January 1, 2016)	Exhibit 10.7(a) to Form 10-K for fiscal year ended September 30, 2016 (File No. 1-10042)
10.7(b)*	Atmos Energy Corporation Performance-Based Supplemental Executive Benefits Plan Trust Agreement, Effective Date December 1, 2000	Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042)
10.8*	Atmos Energy Corporation Account Balance Supplemental Executive Retirement Plan (As Amended and Restated, Effective as of January 1, 2016)	Exhibit 10.8 to Form 10-K for fiscal year ended September 30, 2016 (File No. 1-10042)
10.9(a)*	Mini-Med/Dental Benefit Extension Agreement dated October 1, 1994	Exhibit 10.28(f) to Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042)
10.9(b)*	Amendment No. 1 to Mini-Med/Dental Benefit Extension Agreement dated August 14, 2001	Exhibit 10.28(g) to Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042)
10.9(c)*	Amendment No. 2 to Mini-Med/Dental Benefit Extension Agreement dated December 31, 2002	Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2002 (File No. 1-10042)
10.10*	Atmos Energy Corporation Equity Incentive and Deferred Compensation Plan for Non-Employee Directors, Amended and Restated as of January 1, 2012	Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2011 (File No. 1-10042)
10.11(a)*	Atmos Energy Corporation 1998 Long-Term Incentive Plan (as amended and restated February 3, 2016)	Exhibit 99.1 to Form S-8 dated March 29, 2016 (File No. 333-210461)
10.11(b)*	Form of Award Agreement of Time-Lapse Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	
10.11(c)*	Form of Award Agreement of Performance-Based Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	
	Other Exhibits, as indicated	
21	Subsidiaries of the registrant	
23.1	Consent of independent registered public accounting firm, Ernst & Young LLP	
24	Power of Attorney	Signature page of Form 10-K for fiscal year ended September 30, 2018
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications**	
	Interactive Data File	
101.INS	XBRL Instance Document	
101.SCH	XBRL Taxonomy Extension Schema	

101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

* This exhibit constitutes a "management contract or compensatory plan, contract, or arrangement."

** These certifications pursuant to 18 U.S.C. Section 1350 by the Company's Chief Executive Officer and Chief Financial Officer, furnished as Exhibit 32 to this Annual Report on Form 10-K, will not be deemed to be filed with the Securities and Exchange Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ CHRISTOPHER T. FORSYTHE

Christopher T. Forsythe
Senior Vice President and
Chief Financial Officer

Date: November 13, 2018

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints Michael E. Haefner and Christopher T. Forsythe, or either of them acting alone or together, as his true and lawful attorney-in-fact and agent with full power to act alone, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ KIM R. COCKLIN Kim R. Cocklin	Executive Chairman of the Board	November 13, 2018
/s/ MICHAEL E. HAEFNER Michael E. Haefner	President, Chief Executive Officer and Director	November 13, 2018
/s/ CHRISTOPHER T. FORSYTHE Christopher T. Forsythe	Senior Vice President and Chief Financial Officer	November 13, 2018
/s/ RICHARD M. THOMAS Richard M. Thomas	Vice President and Controller (Principal Accounting Officer)	November 13, 2018
/s/ ROBERT W. BEST Robert W. Best	Director	November 13, 2018
/s/ KELLY H. COMPTON Kelly H. Compton	Director	November 13, 2018
/s/ SEAN DONOHUE Sean Donohue	Director	November 13, 2018
/s/ RUBEN E. ESQUIVEL Ruben E. Esquivel	Director	November 13, 2018
/s/ RAFAEL G. GARZA Rafael G. Garza	Director	November 13, 2018
/s/ RICHARD K. GORDON Richard K. Gordon	Director	November 13, 2018
/s/ ROBERT C. GRABLE Robert C. Grable	Director	November 13, 2018
/s/ NANCY K. QUINN Nancy K. Quinn	Director	November 13, 2018
/s/ RICHARD A. SAMPSON Richard A. Sampson	Director	November 13, 2018
/s/ STEPHEN R. SPRINGER Stephen R. Springer	Director	November 13, 2018
/s/ DIANA J. WALTERS Diana J. Walters	Director	November 13, 2018
/s/ RICHARD WARE II Richard Ware II	Director	November 13, 2018

Schedule II

ATMOS ENERGY CORPORATION

Valuation and Qualifying Accounts
Three Years Ended September 30, 2018

	Balance at beginning of period	Additions: Charged to cost & expenses	Additions: Charged to other accounts	Deductions	Balance at end of period
		(In thousands)			
2018					
Allowance for doubtful accounts	$ 10,865	$ 14,894	$ —	$ 10,964 (1)	$ 14,795
2017					
Allowance for doubtful accounts	$ 11,056	$ 12,269	$ —	$ 12,460 (1)	$ 10,865
2016					
Allowance for doubtful accounts	$ 12,934	$ 10,414	$ —	$ 12,292 (1)	$ 11,056

(1) Uncollectible accounts written off.